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U.S. Vulnerability to an Oil Import Curtailment

The Oil Replacement Capability

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Foreword

This report responds to a request by the Senate Committee on Foreign Relations for an analysis of the U.S. oil replacement capability in the event of an oil supply shortfall of indefinite duration. The assessment complements several other OTA reports related to energy efficiency and oil replacement: *Residential Energy Conservation, Energy Efficiency of Buildings in Cities, Industrial Energy Use, Increased Automobile Fuel Efficiency and Synthetic Fuels: Alternatives for Reducing Oil Imports,* and *Energy From Biological Processes.*

The report analyzes energy supply and demand technologies which can replace large amounts of oil within 5 years after the onset of a major oil supply shortfall, occurring within the next few years and accompanied by a large and enduring increase in oil prices. Emphasis is placed on those technologies that are commercially available now or are likely to be commercial by 1985, and, within this group, attention is given to the least cost alternatives to oil. In addition, the report analyzes the macroeconomic effects of an oil shortfall and how these effects could be influenced by different rates of investment in the oil replacement technologies.

In the course of this assessment, OTA drew on the experience of many organizations and individuals. In particular, we appreciate the generous assistance of our advisory panel as well as the efforts of the project's consultants and contractors. We would also like to acknowledge the help of the numerous reviewers who gave their time to ensure the accuracy and comprehensiveness of this report. To all the above goes the gratitude of OTA, and the personal thanks of the project staff. It should be understood, however, that OTA assumes full responsibility for this report, which does not necessarily represent the views of individual members of the advisory panel.

John H. Gibbons

JOHN H. GIBBONS
Director

U.S. Vulnerability to an Oil Import Curtailment Advisory Panel

Rodney W. Nichols, *Chairman*
Executive Vice President, The Rockefeller University

Al Alm*
Deputy Administrator
U.S. Environmental Protection Agency

Richard E. Archer
Design Program
Southern Illinois University

Jan Brinch
Mueller Associates, Inc.

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Department of Political Science
Massachusetts Institute of Technology

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Senior Vice President
Foster Wheeler Corp.

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American Telephone & Telegraph Co.

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and Development Authority

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Sacramento, California

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Deputy Director
Illinois Department of Nuclear Safety

Ray Maliszewski
Assistant Vice President
Bulk Transmission Planning
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Director, Energy and Environment
National Audubon Society

Richard A. Rettig
Department of Social Sciences
Illinois Institute of Technology

Walter S. Salant
The Brookings Institution

Joanna Underwood
Executive Director
INFORM

R. Fred Wilson
Assistant to the Senior Vice President
Texaco, Inc.

Herb H. Woodson
Director, Center for Energy Studies
University of Texas

---

*Formerly with John F. Kennedy School, Cambridge, Massachusetts.
**Formerly with the California State Energy Commission.
***Formerly Science Director, Scientists' Institute for Public Information.

U.S. Vulnerability to an Oil Import Curtailment OTA Staff

Lionel S. Johns, *Assistant Director, OTA*
Energy, Materials and International Security Division

Richard E. Rowberg, *Energy and Materials Program Manager*

Thomas E. Bull, *Project Director*

Nancy Naismith, *Project Director**

James F. Ryan   Joanne M. Sedor   David Strom   Richard Thoreson
Kathryn M. Van Wyk, *Editor*

Administrative Staff

Lillian Quigg   Edna Saunders

Contractors/Consultants

Gibbs & Hill, Inc., New York
Interindustry Economic Research Fund, Inc., College Park, MD
Dale Jorgenson Associates, Cambridge, MA
Energy & Environmental Analysis, Inc., Arlington, VA
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Rasor Associates, Inc., Sunnyvale, CA
Ransom & Casazza, Inc., Washington, DC
David H. Hunsberger, Washington, DC
Philippe Becker, Berkeley, CA
Wallace Tyner, West Lafayette, IN

---

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TIPI Workshop
Allenspark, Colorado

Dallas Dawsen
American Gas Association

Ev Ehrlich
Congressional Budget Office

Wayne Ferris
General Accounting Office

Keith Frye
U.S. Department of Energy

Linda Gaines
Argonne National Laboratory

Michael I. German
American Gas Association

R. F. Giese
Argonne National Laboratory

Burl Haigwood
Renewable Fuels Association

David Hallberg
Renewable Fuels Association

Richard Harrington
U.S. Department of Energy

K. Hub
Argonne National Laboratory

Larry R. Johnson
Argonne National Laboratory

Thomas Milne
Solar Energy Research Institute

Kevin M. Myles
Argonne National Laboratory

Sidney R. Orem
Industrial Gas Cleaning Institute

Frank T. Princiotta
U.S. Environmental Protection Agency

Jerry Ramsey
U.S. Department of Energy

Thomas Reed
Solar Energy Research Institute

Norman F. Sather
Argonne National Laboratory

Benjamin Schlesinger
Booz, Allen & Hamilton, Inc.

Bettina Silber
Americans for Energy Independence

Thomas Stern
Americans for Energy Independence

Al Sobey
General Motors Corp.

J. Stavrou
Argonne National Laboratory

George Stosur
U.S. Department of Energy

Jim White
U.S. Department of Energy

A. M. Wolsky
Argonne National Laboratory

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Chapter I

Introduction

Chapter I
Introduction

The U.S. economy and energy supply system were jolted by two oil supply disruptions during the decade of the 1970s. In each case, deliveries of liquid fuels were restricted or unreliable for several months after the onset of the disruptions, and oil prices rose rapidly. Following these initial instabilities, deliveries became more reliable; but petroleum prices remained permanently higher[1] than before the disruptions, a situation that is economically equivalent to a permanent reduction in petroleum supplies. Thus, both disruptions can be characterized as resulting in a temporary period of instability, but a permanent reduction in oil supplies.

The disruptions and supply shortfalls during the 1970s have created substantial economic problems for the United States and changed U.S. thinking about the importance to the United States of energy and of a stable energy supply. The recessions and inflation during that period were due in part to the large, permanent oil price increases. In addition, the dependence of the United States and its allies on imported oil has intensified the already critical strategic problem of the Middle East, and the United States has invested and is continuing to invest considerable sums of money to establish a strategic petroleum reserve capable of cushioning any further shocks.

Another response to the higher oil prices has been the considerable change in oil use in the United States. Oil demand in 1983 was down about 20 percent from the peak year of 1978, and U.S. net oil imports dropped from about 8.6 million barrels per day (MMB/D) in 1977 to about 4.3 MMB/D in 1983. This change is a result of conservation and fuel switching, as well as reduced and changed economic activity. Because of these substantial import reductions, which have also occurred in other oil-importing nations, the amount of oil exported from the Middle East has declined by about 10 MMB/D since 1978. Indeed, the decline in world demand has been considerably larger than the loss of oil exports from Iran and Iraq resulting from the Iran/Iraq War.

Given these conditions, the natural question is how much should the United States be concerned about the possibility of another curtailment of oil supplies to this country. The problem is still very serious. Despite their large drop, oil imports are still a significant fraction (about 30 percent) of total U.S. oil demand. And even though the U.S. economy is considerably more energy efficient, continued economic growth is still heavily dependent on a steady supply of energy at relatively stable prices. In addition, the responses constructed so far to deal with a possible future shortfall are only able to cushion the shock and relieve supply restrictions over a period of about a year or so. Judging from the previous disruptions, however, a future shortfall is likely to be, in effect, permanent. Finally, there are circumstances under which the supply of oil could again be dramatically reduced. For example, a major war in the Middle East could destroy the production capacity of the large producers for several years. Indeed the war between Iran and Iraq has significantly reduced those countries' export capability for the last 5 years and there are signs that this war could spread to other parts of the Persian Gulf.

To investigate possible U.S. responses to a sudden and permanent reduction in oil supplies to the United States, OTA has assessed the nonmilitary technological measures that could be taken to replace large amounts of oil within 5 years after the onset of a supply shortfall. This assessment does not explicitly address emergency management strategies (e.g., a drawdown of the Strategic Petroleum Reserve and private oil stockpiles) designed to minimize the initial instabilities following a disruption, although such measures would be needed. **Rather, it focuses on an evaluation of the rates that energy technologies could be deployed to replace the lost oil following a shortfall and on the economic impacts and**

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[1] Following the 1973-74 disruption, real oil prices rose by about 120 percent and remained at that level. After the 1979 disruption, real oil prices peaked in 1981 at 120 percent higher than their 1978 level. By early 1984, 5 years after the onset of the disruption, oil prices remained at about 60 percent above their 1978 level. Economic recovery from the current recession is likely to put some upward pressure on oil prices in the years ahead.

potential market clearing price of oil associated with different rates of deployment.

Initially, OTA considered a wide variety of technologies for reducing U.S. oil consumption, including technologies for switching from oil to other fuels and for increasing the efficiency of oil use. The technologies that show the most promise for replacing large quantities of oil within 5 years after the onset of a supply shortfall (assumed to begin in 1985) were then considered in more detail. Potential deployment rates for these latter technologies were derived, based on historical peak rates of deployment, estimates of production capacities for the needed equipment, assumptions about U.S. oil consumption in 1985, and other relevant factors. An alternative deployment scenario was then also derived, based on more pessimistic assumptions about the rates of investment in the energy technologies.

To study potential economic impacts, it is necessary to specify the magnitude of the potential oil supply shortfall. Since OTA is primarily interested in studying the effects of oil replacement technologies, the postulated shortfall should be relatively large, so that it cannot be accommodated solely through relatively minor economic and behavioral adjustments. One such possibility might be the cessation of oil exports from the Persian Gulf countries. As of mid-1983, these countries exported a little more than 9 MMB/D, down from about 14.4 MMB/D in 1981 (mostly due to a reduction in Saudi Arabian production).[2] Since the U.S. accounts for about one-third of the non-Communist world oil consumption, the U.S. share of a 9 MMB/D world oil shortfall would be about 3 MMB/D.[3] Other scenarios are possible, ranging up to a U.S. shortfall of nearly 5 MMB/D, if Persian Gulf exports return to their 1981 levels;[4] but 3 MMB/D is more plausible and is adequate to illustrate the effects of deploying the oil replacement technologies. **Consequently, for the purposes of this analysis we have assumed that the U.S. oil shortfall would be 3 MMB/D starting in mid-1985.**

Based on this hypothesis, on assumptions about the rate that oil stocks would be drawn down,[5] and on the technical analysis, OTA modified and used a macroeconomic model of the U.S. economy[6] to estimate plausible economic impacts of the oil shortfall with different rates for deploying the oil replacement technologies. The difference in the economic impacts associated with the two technology deployment scenarios then served as a principal measure of the effects of deploying these technologies.

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[2] Exports in 1981 are based on production of 16 MMB/D and consumption of 1.6 MMB/D by these countries ("BP Statistical Review of World Energy 1981," British Petroleum Co., Britannic House, Moor Lane, London E2CY 9BU.). Mid-1983 exports are based on production of 10.5 MMB/D ("Monthly Energy Review," DOE/EIA-0035(83/10), October 1983) and an assumed consumption of 1.4 MMB/D.

[3] If U.S. oil prices are allowed to rise to world levels during the shortfall and U.S. price elasticity of demand is the same as in other countries in the world, then each country's consumption would drop in proportion to its consumption before the shortfall. The elasticity of oil demand in the United States, however, may be greater than in most other industrialized countries because U.S. energy use is generally less efficient. Furthermore, because U.S. consumer oil prices are generally lower than in other industrialized countries, the percentage increase in U.S. oil prices could be larger than elsewhere. If so, the reduction in U.S. oil consumption could be proportionately greater than in other industrialized countries. On the other hand, the fact that about two-thirds of the U.S. oil consumption is domestically produced means that the flow of capital out of the country to pay for imported oil would be significantly less (relative to gross national product) than in many other industrialized countries. Thus, the drop in industrial output and the consequent relative reduction in oil consumption in some of these countries could be larger than in the United States.

[4] As mentioned in the text, Persian Gulf countries exported about 14.4 MMB/D in 1981. With a world oil shortfall of this size, then under the International Energy Agreement (IEA) the United States would have to reduce its consumption by about 3.4 MMB/D (less the emergency reserve drawdown obligation). In that year, however, the U.S. oil use was 32.9 percent of world oil consumption (excluding U.S.S.R., China, and Eastern Europe). Consequently, in the absence of the IEA allocations and market pricing of oil in the United States, the U.S. share of a 14.4 MMB/D world shortfall would be 0.329 × 14.4 = 4.7 MMB/D. For a 10 MMB/D world oil shortfall, the U.S. share would be 2.5 MMB/D under the IEA and 3.3 MMB/D in the absence of IEA allocations. The corresponding numbers under a 5 MMB/D shortfall are 1.4 MMB/D and 1.6 MMB/D, respectively. (These calculations are based on 1981 production and consumption figures from "BP Statistical Review of World Energy 1981," British Petroleum Co., Britannic House, Moor Lane, London E2CY 9BU and the text and sample calculation in "Agreement on an International Energy Program (as amended to 19th May, 1980)," International Energy Agency.) Despite the fact that adherence to the IEA would provide the United States with larger supplies of oil than would the free market (after initial adjustments), the IEA may nevertheless be viewed initially by the public as being unfair to the United States. Since the United States imports most of its oil from sources other than Persian Gulf countries, a cessation of oil exports from the Persian Gulf would not have a large immediate effect on U.S. imports. Under the IEA, however, the United States would have to divert some of its imports to other IEA member countries. Although the international oil market would eventually divert larger amounts of our imports to these other IEA member countries, the initial, organized diversion may still be viewed with some suspicion in the United States.

[5] In both scenarios, the Strategic Petroleum Reserve (SPR) and private oil stockpiles are assumed to be drawn down at a rate starting at 1.5 MMB/D and dropping to 0.75 MMB/D after 1 year, 0.38 MMB/D after 2 years, and zero at the end of the third year. Consequently, OTA has assumed stocks totaling almost 700 million barrels of oil would be used, of which over half currently is in the SPR. At mid-1983 rates of filling the SPR (0.24 MMB/D), the SPR would reach about 525 million barrels by mid-1985.

In the next chapter, the major issues and findings of the assessment are summarized. Chapter III presents a brief history and current profile of energy and oil use in the United States. Chapters IV and V summarize the technical analyses of the oil replacement potential through fuel switching and conservation, respectively; and chapter VI combines these analyses into overall scenarios, examines the overall changes in fuel use, discusses possible variations on the scenarios, and briefly describes the longer term effects of deploying the technologies. The final chapter gives a description of the economic model and discusses the macroeconomic effects, including the results of the modeling and other relevant economic considerations.

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[6] Inter-Industry Forecasting Model of the University of Maryland.

Chapter II

Summary

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Chapter II
Summary

INTRODUCTION

Since 1973, the United States has experienced two major oil supply disruptions and shortfalls which resulted in large and enduring increases in oil prices. Although the Nation has made great strides in reducing oil consumption in response to those price increases, another disruption and shortfall could still have significant negative consequences for the U.S. economy.

Much of the continuing debate on how to deal with another disruption and shortfall has centered around emergency response mechanisms such as oil stockpiling and standby fuel allocation schemes. Little attention has been paid to ways of responding to a shortfall of indefinite duration because it has always been assumed that any oil cutoff would end after a period of 1 or 2 years. An indefinite shortfall is not implausible, however. Indeed, the lasting increases in oil prices that resulted from events in the 1970s are the economic equivalent of lasting supply shortfalls. And as a result of the most recent shortfall, the period 1978-83 saw a 60-percent increase in the real price of oil and an unadjusted decline in oil demand of nearly 4 million barrels per day (MMB/D).

Judging from this historical experience, therefore, an important aspect of the United States' vulnerability to a future oil import curtailment is the Nation's ability to adjust to a lasting or protracted oil supply shortfall and price rise. As demonstrated by the Nation's response to the most recent price shock, a lasting shortfall would require technological and economic adjustments that go well beyond short-term emergency responses, although those responses would also certainly be necessary.

At the request of the Senate Committee on Foreign Relations, OTA addressed the possibility of a lasting shortfall by asking the following questions: how could the United States respond to a large and protracted oil supply shortfall by technical means alone and how do the economic consequences of a shortfall depend on the deployment rate of oil replacement technologies?

As a starting point for its analysis, OTA made a number of assumptions:

1. Acceptance of the International Energy Program[1] IEA agreements results in a 3 MMB/D[2] shortfall in the United States (compared to a preshortfall demand of 16 MMB/D).
2. The shortfall is assumed to be of indefinite duration (i.e., to last at least 5 years) at the outset and to begin in the mid-1980s.
3. The economy would not undergo major structural changes, such as major shifts in output mix or behavior during the 5-year period.
4. The Strategic Petroleum Reserve, as well as private oil stockpiles, would be used to reduce the immediate effects of the shortfall, but they would be depleted within 3 years, dropping from a drawdown rate of 1.5 MMB/D the first year of the shortfall to zero by the end of the third year.

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[1] "Agreement on an International Energy Program (as amended to 19th May, 1980)," International Energy Agency.

[2] Corresponding to a (non-Communist) world oil shortfall of about 9 to 10 MMB/D.

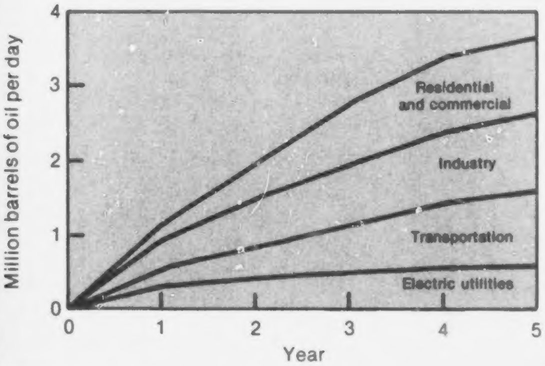
MAJOR FINDINGS

At the onset of an oil supply shortfall, emergency measures such as reductions in private and public oil stocks can cushion the immediate effects of the oil shortfall. After 5 to 10 years, long leadtime technologies such as enhanced oil recovery and synthetic fuels production can begin to provide liquid fuels, which are essentially indistinguishable from the lost oil. In the period of about 1 to 5 years after onset, however, oil consumers will either have to forgo certain energy services or invest in nonoil energy technologies.

OTA has examined each sector in the U.S. economy and identified the technologies that, based on **technical** considerations, are likely to be able to replace the largest quantities of oil, at the least cost, for each sector. The rate that each oil replacement technology (fuel switching and increased efficiency of use) could be deployed was then estimated from existing capacities to produce and install the necessary equipment, historical peak rates of installation and various end-user constraints. Based on this analysis, **OTA has concluded that the United States has the technical and manufacturing capability to replace up to 3.6 MMB/D of oil use within 5 years after the onset of an oil supply shortfall** (see fig. 1 and table 1).

The criteria used to select the most promising technologies for each major end use of oil were: 1) the technology must be commercial now or is likely to be commercial by mid-1985, 2) individual units can be installed or built in less than 2 to 3 years, 3) the technology has sufficiently broad applicability to be capable of replacing a significant fraction of the oil consumed for that end use, and 4) the technology is currently among the lowest cost alternatives to oil for that end use. In other words, OTA selected those technologies that—based on current engineering cost estimates and technical judgments—could replace large quantities of oil in a relatively short time at costs below OTA's estimate of the probable post-shortfall price of oil ($50 to $70 per barrel in 1983 dollars).

Figure 1.—Potential Replacement of Oil Through Fuel Switching and Increased Efficiency



SOURCE: Office of Technology Assessment.

Inflation following a large oil shortfall will, of course, increase the cost of many of these oil replacement technologies, and it could alter the relative costs among the technologies. These changes will depend on a complex variety of factors and, currently, there is no good way to predict the actual outcome. Nevertheless, the difference between the current costs of the major replacement technologies selected and the probable post-shortfall price of oil is sufficiently large to warrant reasonable confidence that these technologies will be economic alternatives to oil following a large shortfall.

The options satisfying these criteria that can replace the largest amounts of oil within 5 years after the start of a shortfall are:

1. increased efficiency and switching to alternative fuels to reduce oil use for space and water heating in buildings and for steam in industry and electric utilities, and
2. increased average efficiency of automobiles and light trucks on the road.

Smaller, additional amounts of oil can be replaced in transportation and materials uses of oil (e.g., petrochemicals) using a variety of other technologies, but the near- to mid-term opportunities are more limited because of longer leadtimes and/or higher costs.

At the end of 5 years, deployment of the major oil replacement technologies would leave transportation fuels and materials production as the predominant remaining uses for oil. Aside from refinery use of oil for fuel (8 to 10 percent of refinery throughputs), less than 5 percent of the remaining oil consumption would be for space and water heating and steam, mostly in residential and commercial buildings in the northeastern United States and in small industrial boilers throughout the country.

This oil replacement would require about 2 trillion cubic feet (TCF) of natural gas (11 percent of 1982 consumption) and 115 million tons of

Table 1.—Major Oil Replacement Options

Sector	Oil replacement potential after 5 years (MMB/D)[a]
Electric utilities:	
Switching to coal and completion of new powerplants currently under construction	0.5
Increased use of natural gas	0.1
Subtotal	0.6
Industry:	
Switch to natural gas	0.45
Switch to coal	0.2
Increased efficiency	0.15
Reduced refinery throughput	0.2
Subtotal	1.0
Residential and commercial (heat and hot water in buildings):	
Switch to natural gas	0.45
Switch to electricity	0.4
Increased efficiency and switch to other fuels	0.15
Subtotal	1.0
Transportation:	
Increased efficiency of cars and light trucks	0.7
Increased efficiency in other transportation modes	0.1
Increased production and use of ethanol	0.1
Switch to other alternative transportation fuels	0.1
Subtotal	1.0
Total	3.6

[a]Numbers rounded to nearest 0.05 MMB/D

SOURCE: Office of Technology Assessment

solid fuels (coal and wood) per year (13 percent of 1982 production) as substitutes for oil. Nearly all of the increment of natural gas, however, could be made available through investments in increased efficiency of natural gas use.

End-user investment costs for the major oil replacement technologies can vary from $0 to $5,000 per barrel per day (B/D) of oil replaced (for conversion of an industrial boiler to natural gas) up to $35,000 to $60,000 per B/D of oil replaced (for installation of a central electric heat pump for residential space heating and hot water) (see table 2). However, with residential electricity costing 8 cents per kilowatthour (kWh) (1983 average was 7.2 cents/kWh), even the cost of installing a heat pump in an average oil-heated residential building could be recovered in 2 to 6 years, depending on the price of oil following the shortfall and on the actual investment cost. The payback period for the other options considered would be shorter, unless there were rapid inflation in equipment costs and/or natural gas prices. (Although some inflation in the price of equipment would be expected, as mentioned above, there is no fundamental reason why these prices should become prohibitively high. Furthermore, natural gas price rises could be moderated by investments in increased efficiency of natural gas use, with investment costs similar to those for increased efficiency of oil use.)

Total investment would amount to $30 billion to $40 billion per year,[3] on average, or about 7 to 9 percent of recent annual investments in producer durables and residential structures.

Although the anticipation of large increases in the price of oil would be a strong incentive to invest in oil replacement technologies, nontechnical constraints could limit the actual rate of investment in these technologies to a level which is considerably lower than the rate at which the technologies could be supplied. For example, in-

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[3] The higher number includes investments to increase the efficiency of natural gas use. The numbers do not, however, include the cost of new car and light truck purchases because this involves an ongoing activity.

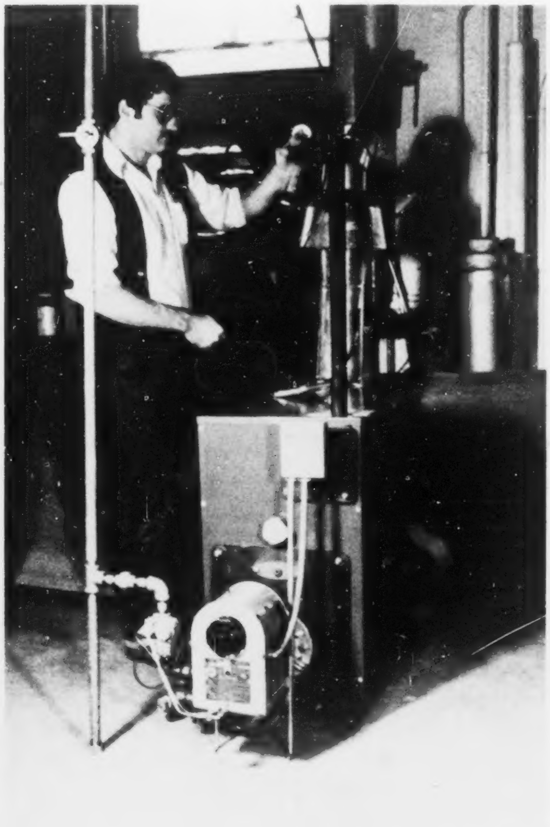

Photo credit: Midco Corp.

Many oil-fired boilers used for home heating and hot water can be converted to natural gas simply by the addition of a gas burner (circled)

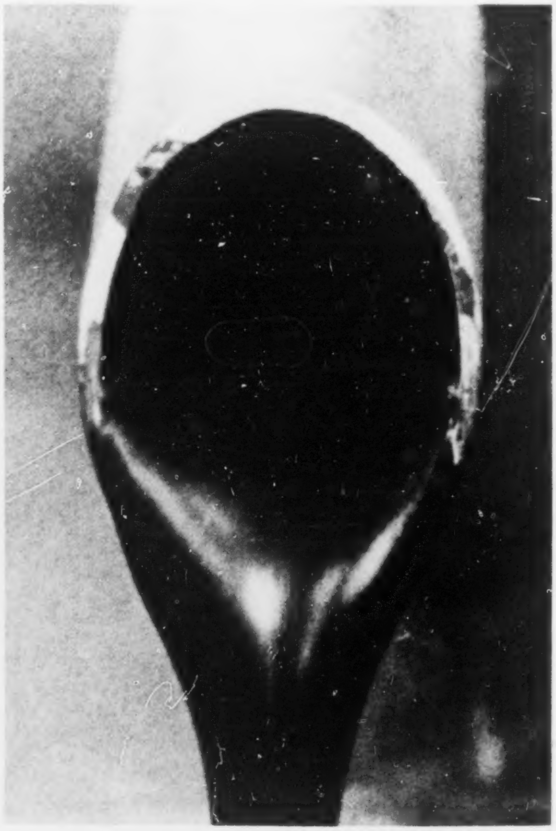

Photo credit: Atlantic Research Corp.

A coal-water mixture flows from a pipe at an Atlantic Research Corp. facility. Such mixtures contain up to 70 percent coal in water together with small amounts of stabilizing agents. Because the mixtures are fluid, they can be stored and delivered in systems similar to those used for oil, thereby eliminating the need for a coal yard at the end user's location

dustrial oil users may shut down their plants rather than make large investments in the face of an uncertain future demand for their products. Electric utilities using oil may have difficulties borrowing money in the bond markets particularly if their current financial health does not improve and regulatory climate does not change to facilitate these investments. Further, if electric rates increase after the onset of the shortfall, a drop in demand for electricity could further deteriorate utilities' financial situation. There could also be delays in issuing construction permits for converting industrial and utility boilers to coal and in issuing operating permits and certification for new electric powerplants. States that produce high-sulfur coal may resist the use of low-sulfur coal in these conversions (needed to meet emissions standards[4] while minimizing the investment and construction time). Consumers may defer the purchase of new (more fuel efficient) automobiles.

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[4] Converting boilers from residual fuel oil to coal will not increase sulfur and particulate emissions if low-sulfur coal is used and particulate control devices are installed. Emissions of some other pollutants, involving impurities found in coal but not in residual oil, ash disposal, and mining-related impacts would increase, however. Furthermore, about one-third of the roughly 100 million ton/yr increase in coal use would be in existing and new electric powerplants and would be used to replace home heating oil. This replacement of oil with coal would lead to net increases in sulfur, particulate, NO_x, and other emissions associated with coal. The magnitude of the increase would depend on how much of the coal is burned in new and existing powerplants with efficient emission controls versus the amount burned in existing powerplants with inefficient controls. Presumably most of the marginal electric generation would be in new powerplants meeting new source performance standards.

Table 2.—Estimated Investment Costs for Major Oil Replacement Technologies

Option	Investment cost (thousand 1982 dollars per barrel per day of oil replaced)
• Fuel switching in industrial and utility boilers:	
Conversion to solid fuel (including coal-water mixtures)	10-20
Construction of new solid fuel boiler with coal-handling facility	25-50
Construction of coal-water mixture production plant	2-3
Completion of new powerplants currently under construction[a]	50[a]
Conversion to natural gas	0-5
• Fuel switching in residential and commercial space heating and hot water:	
Natural gas	15-25
Electric heat pumps	35-60[b]
Electric resistance heating	10-20[c]
Solid fuel	5-35[d]
• Residential and commercial energy conservation:	
Building insulation	40-60[e]
• Industrial oil replacement:	
Amalgam of efficiency improvements and product mix shifts	10-70[f]

[a] Assumes $500 per kilowatthour to complete and plant operation at 70 percent of capacity.

[b] Based on an installation cost ranging from $2,000 to $3,500 for a system used only for space heating to $2,500 to $4,000 for a system for space heat and hot water and on the national average oil use of 676 gal and 1,055 gal per year for homes in which oil provides heat only, and both heat and hot water, respectively.

[c] Assumes $500 per household for electric resistance space heaters and $1,000 for a hot water heater.

[d] Assumes $250 to $750 for wood stove (including installation) for space heating only or $2,500 for new wood-fired central boiler for heat and hot water.

[e] This estimate represents an average over a number of building types and ages. Actual site-specific costs will vary from less than $1,000 per B/D up to over $200,000 per B/D.

[f] Industrial replacement involves a broad range for investment costs. At the low-cost end, investment is incidental (e.g., for product mix shifts); and at the high-cost end, investments are large because firms are willing to pay an insurance premium in order to increase the security or price stability of its fuel supplies.

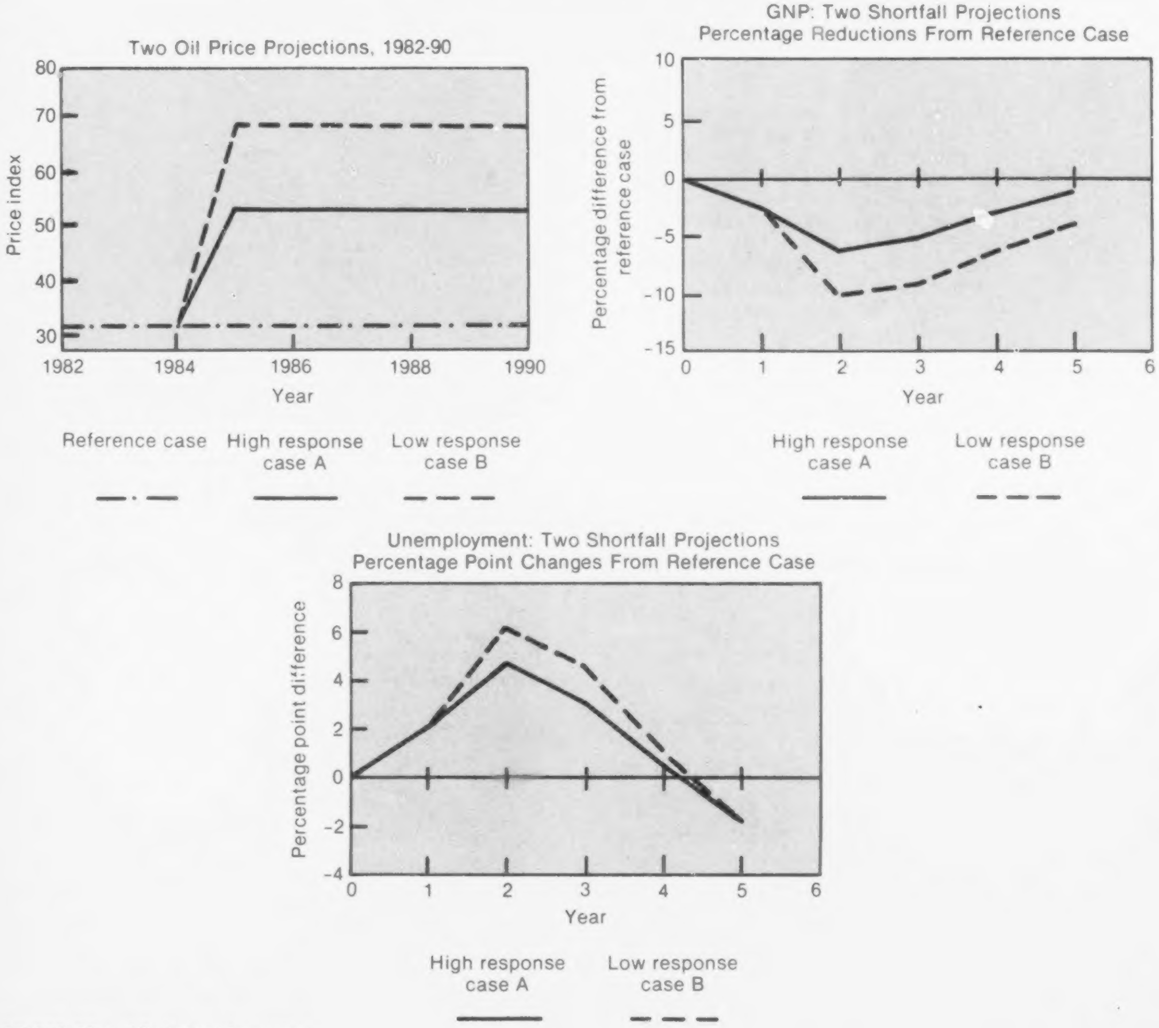
SOURCE: Office of Technology Assessment and Gibbs & Hill, Inc., "Oil Replacement Analysis Phase I—Selection of Technologies," contractor report to Office of Technology Assessment, April 1983.

And residential and commercial oil users may be unable or unwilling to invest in increased efficiency and new heating and hot water equipment at a time when their heating bills are putting a strain on their finances; they may simply be ignorant of their options; or, if they are tenants, they may be unable to convince their landlords of the need for the investments. Similar reasons as well as continued price controls on natural gas may inhibit investments by natural gas consumers in measures to increase the efficiency of gas use. As a result, there may be inadequate supplies of natural gas to achieve this level of oil replacement.

Because there is considerable uncertainty about the rate at which oil (and possibly gas) users actually will invest in replacement technologies, OTA derived two plausible replacement scenarios: one, in which the full 3 MMB/D shortfall is replaced with these technologies within 5 years (case A), and another, in which the investment rate is slower and only half this amount is replaced after 5 years (case B).

Although the economic consequences in both response cases would be substantial, the rapid response requires no major changes in the industrial mix of the economy nor permanent curtailments in energy services. Macroeconomic projections indicate that **the rapid response would create significantly less severe economic consequences than a slower, more constrained response.** The average loss in gross national product (GNP) over the 5-year period is significantly less (40 percent) for case A than for case B, employment losses are 30 percent lower for case A than B, and the oil price rise during case A is about half of the case B increase (see fig. 2). Furthermore, although employment is similar after

Figure 2.—Economic Comparison of Two Oil Replacement Scenarios



SOURCE: Office of Technology Assessment.

the 5-year period for the two cases, in case B, the employment level is brought back at the expense of lower labor productivity.

In other words, **to the extent that the lost oil is not replaced through investment in replacement technologies, oil consumption must be lowered through reduced economic activity and personal consumption.** While the total investment cost of the rapid response would be substantial, the investments would result in a lower net cost to the economy than that in the slower, more constrained response.

In addition, there will be a strong interaction between the rate of oil replacement by investment in energy technologies and the state of the economy. The faster rate of oil replacement restrains the growth in oil prices thereby increasing disposable income. This, in turn, improves the investment climate, thereby reinforcing the incentives to make these oil replacement investments. Conversely, investor reticence could lead to a recession which is more severe than that dictated by the magnitude of the shortfall; and this reticence could be self reinforcing leading to a severe recessionary spiral. **Stability** therefore is also a very important concern.

If the low rate of investment occurs, however, two additional factors must be considered before one can conclude that incentives to increase the rate of investment in the replacement technologies will reduce the adverse economic effects. First, oil must be more expensive than the replacement technologies. If it is not, incentives to invest in replacement technologies could still stimulate the economy; but the stimulative effect would be greater if the incentives were directed toward more profitable investments (or towards investment in general). **OTA's analysis indicates, however, that with a real shortage of 3 MMB/D and with market pricing, oil prices would be higher than the cost of the major fuel switching and conservation technologies considered.**

Second, the general level of investment in producer and consumer durables must be below normal levels. If it is not, incentives to invest in replacement technologies could increase overall investments somewhat, but they could also stimulate inflation and divert some resources from more profitable investments, which could reduce the overall productivity of the economy in the mid to long term. Historical data,[5] however, indicate that expenditures for producer and consumer durables dropped following the 1973-74 and 1978-79 oil crises. One would expect a similar behavior following the large oil shortfall considered here; and, in any case, the level of these investments can be followed using existing systems of data collection and analysis.

Considering the uncertainties, the importance of a stable economy, and the significant differences in the economic impacts associated with the rapid versus the slow response, it would be prudent to prepare to stimulate the rapid response, if necessary, and to maintain a stable economic environment. **Although OTA found that the rapid deployment rate could be achieved without government-mandated conversions of production facilities to supply energy technologies, advanced planning by Federal and State governments is needed.**

A system for monitoring directly the rate of investments in oil replacement technologies would have to be established. In some sectors (i.e., new automobile sales and electric utility fuel use), the monitoring apparatus already exists, but care should be taken to ensure that the results are analyzed and published regularly and promptly. In other areas, data collection will have to be modified or expanded. In all cases, the data collection and analysis should be specifically designed to measure the rates of investment in oil replacement technologies and the quantities of oil replaced. And, to be most effective, the monitoring system should be in place and functioning prior to onset of an oil shortfall in order to provide operating experience and a historical data set to aid analysis of the data collected following the onset of a shortfall.

Various levels of contingent incentives, ranging from information and technical assistance to economic incentives and, finally, regulation could also be established to stimulate investment in oil replacement technologies. Removal of those economic regulations that inhibit investments in some of these technologies may also be needed. The details of these incentives and measures, including specific procedures, responsibilities, and implementation plans, should be established before a shortfall so that incentives tailored to individual end uses and energy sectors can be implemented quickly and smoothly if needed.

In the event of a shortfall, the first level of incentives, involving information dissemination and technical assistance, could be initiated immediately. Economic incentives could be introduced if, after perhaps 6 months to 1 year, investments lag significantly behind the rate that the technologies can be supplied, the general level of investment in consumer and producer durables is depressed, the price of oil has risen at least 50 percent (in real terms), and other economic indicators (e.g., the stability of oil prices, trends in employment and GNP, and speculative investment in oil) suggest the necessity or advisability of further government action. The incentives could then be increased successively until an acceptable rate of investment, as measured by the investment monitoring system, is achieved. In order to avoid the possibility that investors may delay investments in anticipation of future government subsidies, provisions could be included to make any subsidies effective retroactively to the onset of the shortfall.

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[5] "Statistical Abstracts of the United States 1982-83," U.S. Department of Commerce, Bureau of Statistics, December 1982.

In the extreme case, government subsidies may eventually have to pay a large part of the $30 billion to $40 billion per year cost of investments needed for the rapid response plus perhaps $10 billion/yr to promote new car sales. It may be possible to finance these outlays, however, through a windfall profits tax if it were increased so as to collect 50 to 70 percent of the *increased* domestic oil and natural gas liquids production profits resulting from the price rise.[6]

In any case, **ensuring that the rapid response rate can be achieved clearly requires that a decision be made at the highest level that the government will intervene if the market response is overly cautious.** It also requires advance preparation to establish a functioning system which monitors investments in replacement technologies and to develop specific procedures to be used to stimulate investments, if necessary. The uncertainty would have to be removed from the investment climate, and clear signals about the need for investments would be required. But with the willingness to intervene, the ability to measure the relevant investment behavior, and the mechanism to apply successively stronger incentives, it seems likely that the potential benefits of rapidly deploying the replacement technologies could be realized.

Over time, the vulnerability of the United States to a large oil supply shortfall will gradually change. The long-term trend toward reduced consumption of oil for fuel in stationary applications is likely to continue. Eventually, most buildings, manufacturing (except chemicals), and electricity generation will not be directly dependent on oil, and the vulnerability of these sectors to rapid oil price rises will be reduced. As this occurs, however, most of the technologies considered in detail in this report will become increasingly ineffective as cushions against supply shortfalls because they are directed at replacing stationary uses of oil for fuel. In transportation, materials (e.g., chemicals), and off road agricultural, mining, and construction equipment and vehicles—where the remaining oil consumption will be concentrated—the leadtimes for replacing large quantities of oil is long and is likely to remain so.[7]

The results of these changes are ambiguous and partially contradictory. Although reduced U.S. oil consumption would tend to lower the probability and physical magnitude of an oil shortfall, reduced short-term oil replacement capability would tend to increase the price rise associated with a shortfall of any given magnitude. Furthermore, although expenditures for oil may become a smaller fraction of gross domestic expenditures and manufacturing costs (than they would be without the changes), the economic disruption resulting from a shortfall of a given size could be greater, owing to the larger price rise.

OTA's analysis of increased automobile fuel efficiency indicates that even if this option is pursued vigorously and even if stationary (nonfeedstock) uses of oil are eliminated, the United States would still import large quantities of oil by the year 2000, owing primarily to an expected drop in U.S. oil production in the 1990s.[8] And if world oil markets are tight in the 1990s, the United States could be more vulnerable to a shortfall than it was in the 1970s. If oil consumption (in the United States and elsewhere) remaining after these efficiency and fuel switching objectives are accomplished could be reduced and/or replaced with synfuels at a rate that keeps world oil markets slack, however, sudden reductions in production in any given region of the world would have less of an impact because part of the loss would be made up through increased production from underutilized capacity elsewhere.

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[6] For example, with domestic production of 10 MMB/D, a $23 per barrel increase in oil prices (OTA's lower price rise estimate) would increase domestic oil and natural gas liquids production profits by $73 billion/yr. Sixty-eight percent of this is about $50 billion/yr.

[7] See also *Increased Automobile Fuel Efficiency and Synthetic Fuels: Alternatives for Reducing Oil Imports* (Washington, DC: U.S. Congress, Office of Technology Assessment, OTA-E-195, September 1982).

[8] Ibid.; see also *World Petroleum Availability: 1980-2000—A Technical Memorandum* (Washington, DC: U.S. Congress, Office of Technology Assessment, OTA-TM-E-5, October 1980).

SPECIFIC FINDINGS

OTA's analysis of oil replacement technologies indicates that the most effective near- to mid-term replacements for the oil lost in a large shortfall are those that increase end-use efficiency and convert oil users to natural gas and solid fuels (coal, wood, and coal-water mixtures), as well as electricity for space heating and hot water (in parts of the country where there is excess nonoil-fired generating capacity). These technologies are primarily directed at replacing the oil used for space heating, hot water, and steam and at reducing gasoline consumption. Replacing large amounts of nongasoline transportation fuels and oil-based materials (e.g., chemicals, asphalt, lubricants), on the other hand, will require longer leadtimes and, in some cases, more extensive replacement of capital equipment.

Replacing Oil Through Energy Technologies

The potential responses to an oil supply shortfall that begins in 1985 are summarized below for each of the major oil-consuming sectors. The results are then collected into estimates of the overall rate that oil could be replaced within a 5-year period.

Rapid Response—Case A

Utility Use

Electric utilities could begin immediately by using natural gas exclusively in the boilers already equipped to use either oil or natural gas. This change could replace up to 0.2 MMB/D or nearly

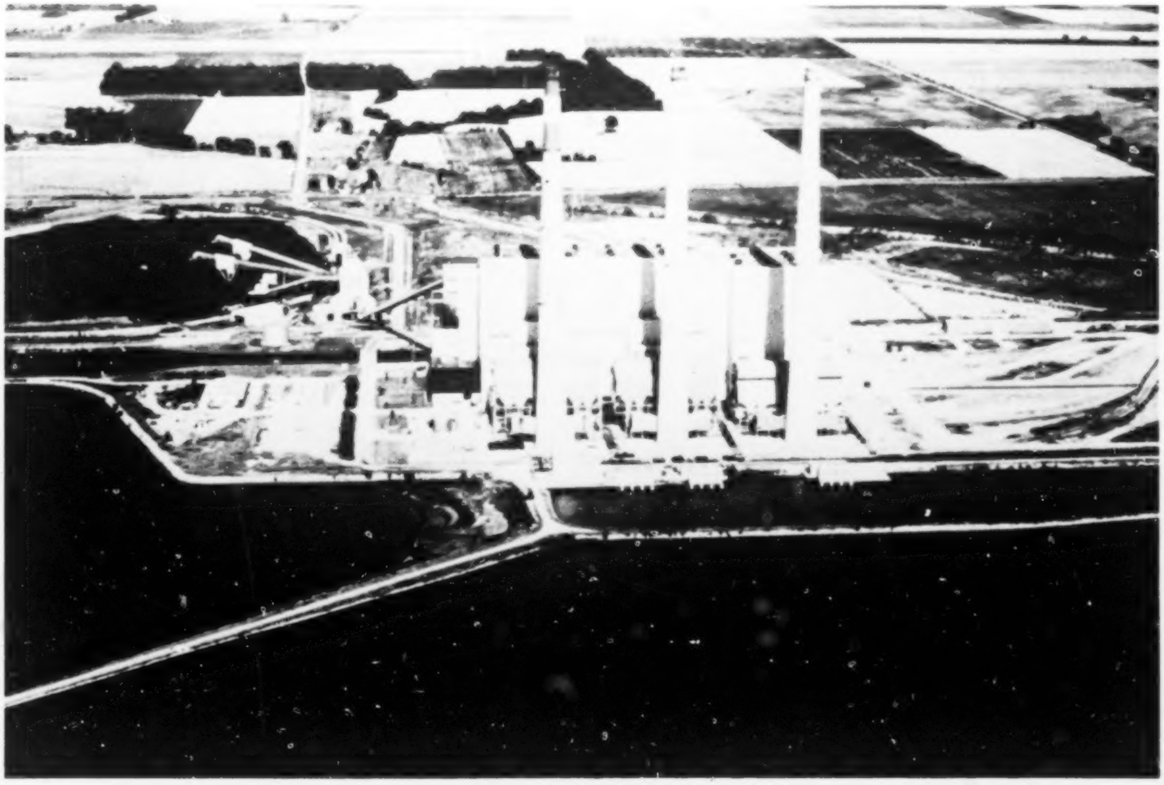

Photo credit: U.S. Department of Energy

Electricity is generated in this modern coal-fired powerplant. The coal yard is to the left one-third of their projected 1985 oil use. However, because OTA has assumed that incremental natural gas supplies are limited and has allocated[9] most of the gas to the residential, commercial, and industrial sectors, the increment of natural gas allocated to utilities at the end of 5 years is only about one-sixth of their projected 1985 oil use. Consequently, their major options for replacing oil are to convert oil-burning boilers to solid fuels and to complete nonoil-fired powerplants now under construction and scheduled for completion between 1985 and 1990.[10] This is particularly true in the Northeast (New England, New York, and New Jersey), where even if all feasible conversions were carried out and all powerplants were completed and brought on line, utilities would still not be able to replace all of the oil used during times of peak demand. Depending on the growth in demand for electricity, a small amount of oil may also have to be burned in utility boilers in Florida, California, and the Mid-Atlantic States, even after feasible conversions to coal and powerplant completions. Most of this oil, however, could probably be replaced with natural gas. In other regions of the country, completion of all powerplants currently under construction is less important, from the standpoint of replacing oil and providing electricity for residential and commercial space heating and hot water.

The solid fuel options include conversions to coal, wood, and coal-water mixtures.[11] The technical changes to the boiler systems (e.g., heat exchanger tube spacing, ash disposal, particulate control systems) are similar for all of the solid fuels, but coal-water mixtures would probably be favored where space limitations prevent construction of solid fuel yards because the mixtures can be prepared offsite and transported, stored, and delivered to the boilers in facilities that are similar to those used for oil (with appropriate changes to valves, pumps, burners, etc.).

In all, utility conversions and completion of plants currently under construction could replace most of the 1985 utility oil use, or about 0.6 MMB/D.

Residential and Commercial Use

Residential and commercial customers can convert to natural gas and electricity for space heating and hot water. In most regions these conversions could virtually eliminate oil use for these purposes. In New England, the New York/New Jersey region, and Hawaii the oil replacement potential from these conversions is more limited, however, because many oil customers are not located near gas lines and electricity generation is heavily dependent on oil.[12] In these regions, therefore, additional oil could be replaced directly by increasing the end-use efficiency and converting to wood and possibly coal (particularly in the Northeast) and solar collectors. Although the latter options are likely to be pursued throughout the country, in regions other than the Northeast and Hawaii they would serve primarily to reduce the incremental demand for natural gas and electricity rather than increase the total technical potential for oil replacement in these sectors. In all, these changes could replace about 1 MMB/D of oil in the residential and commercial sectors.

Industrial Use

The principal replacements for the 1 MMB/D of oil used in industrial boilers are solid fuels and natural gas. The solid fuel technologies include direct combustion[13] of coal, wood, and coal-water mixtures, as well as the use of onsite gasifiers, which convert solid fuels to a low-energy fuel gas. OTA estimates that about two-thirds of the oil used in industrial boilers could be replaced with solid fuels and natural gas within 5 years, but for a variety of reasons, replacing the remaining third would take longer.

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[9] Priority use for the increment of natural gas was assumed to go to residential and commercial customers. The remaining gas was then divided between the industrial and utility sectors in proportion to the amount of oil remaining after the most likely conversions to solid fuels were completed. In all, it was assumed that 2 TCF/yr of natural gas would be available for direct replacement of oil. OTA estimates that increased efficiency of natural gas use in the industrial, residential, and commercial sectors could supply nearly all of this gas.

[10] This obviously does not imply that all powerplants currently under construction can serve as replacements for oil. In many regions, the planned capacity additions greatly exceed the new capacity needed to replace all utility oil use and, at the same time, supply sufficient additional electricity to replace all the oil used for space heat and hot water by residential and commercial customers. In New England, New York, and New Jersey, however, virtually all of the planned capacity additions are needed just to replace most of the oil used by utilities.

[11] Coal-water mixtures are fluid mixtures of pulverized coal and water. These mixtures might typically be 60 percent coal (by weight) and have an energy content of about 3.3 MMBtu per barrel.

[12] Conversions to electricity for heat and hot water could actually increase oil consumption in these regions if they are carried out before the utilities eliminate their oil use. And the delay before utilities can accomplish this limits the oil replacement from conversion to electric heating within the 5-year time period.

Many industrial facilities have limited space to accommodate ash and solid fuel handling facilities and particulate control systems; and many are too old to justify major investments in only a part of the system, even under the conditions of an extended oil supply shortfall. OTA estimates that these constraints would limit solid fuel substitution to about half of the oil used in the large (greater than 50 MMBtu/hr) industrial boilers. This oil, about 0.2 MMB/D, is consumed in about one-fourth of the 4,000 boilers of this size. Additional oil could be replaced by solid fuels if some of the older facilities were scrapped and replaced with new plants capable of using solid fuels, but decisions to do this would be based on a variety of nontechnical factors, which OTA has not analyzed.

All of the constraints mentioned above, as well as some others, are likely to affect conversions of small (less than 50 MMBtu/hr) boilers to solid fuels. For example, there may be difficulties in obtaining reliable fuel supplies; and diseconomies of scale and often low load factors for small boilers increase the cost per unit of oil saved, relative to that of typical large boilers. Furthermore, the production capacity for small boilers (about 1,000 units per year) prevents replacement of more than a small fraction of the 140,000 small industrial oil-burning boilers. Retrofits to gasifiers could be more numerous, but the total fraction of small boilers converted to solid fuels and the oil replaced from these conversions is still likely to be relatively small.

The remaining industrial boilers not converted to solid fuels and near to existing gas lines could be converted to natural gas.[14] However, since OTA has assumed that only 2 TCF of additional gas would be available and that residential and commercial customers would have priority, only about 60 percent of the remaining oil used in industrial boilers could be replaced with gas, owing to limited supplies of this fuel.

In all, OTA estimates that the solid fuel and gas conversions could replace about 0.65 MMB/D of oil from industrial boilers. In addition, increased efficiency in all uses of oil by the industrial sector and reduced oil refinery throughputs could reduce consumption by another 0.37 MMB/D, bringing the total to a little more than 1 MMB/D in 5 years.

Transportation Use

OTA estimates that about 1 MMB/D of oil could be replaced in the transportation sector in about 5 years, with 80 percent of this coming from increased efficiency of automobiles and light trucks. Substantial savings are likely to occur even in the absence of an oil shortfall.[15] Automobile and light truck manufacturers have been converting their plants to produce more efficient vehicles for a number of years, and as these vehicles replace the ones currently on the road, fuel consumption will drop.

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[13] For direct combustion, large boilers could either be modified or replaced with solid fuel boilers, while small boilers are more likely to be replaced.

[14] Obviously, it would be more easily economically justified to extend natural gas lines longer distances to accommodate large boilers and large groups of small boilers than could be justified for isolated small boilers.

[15] Maximum savings could reach nearly 1 MMB/D over the 5-year time period, but actual savings will depend on the demand for fuel efficiency in new cars *and* the volume of new car sales. In a crisis, new car sales are likely to slump (which would reduce the savings), while demand for fuel efficiency would increase (which would increase savings). These two factors tend to cancel each other out. For example, OTA estimates that with average annual new car sales of 11 million vehicles/yr and a 1990 new car fuel efficiency of 27.5 miles per gallon (mpg), the fuel savings between 1985 and 1990 would be about the same as with annual new car sales of 7 million vehicles and a 1990 new car fuel efficiency of 36 mpg, or about 0.8 MMB/D for cars and light trucks (assuming light truck sales and efficiencies mimic those of cars). In the extreme case, where automobile sales slump to 5 million vehicles annually and 1985 new car efficiency is 25 mpg, rising only to 32 mpg by 1990, savings would still be about 0.5 MMB/D. (See also *Increased Automobile Fuel Efficiency and Synthetic Fuels: Alternatives for Reducing Oil Imports*, op. cit.

In addition, smaller savings are possible through shifts in the modes of freight transport (from planes to trucks, trucks to rail, and rail to water transport), marginal increases in the efficiency of freight and commercial passenger transport, increased production of fuel ethanol (for alcohol blends in gasoline), and conversions to compressed natural gas, liquefied petroleum gas, and (possibly) mobile gasifiers, which convert solid fuels to a fuel gas on board the vehicle.

Total

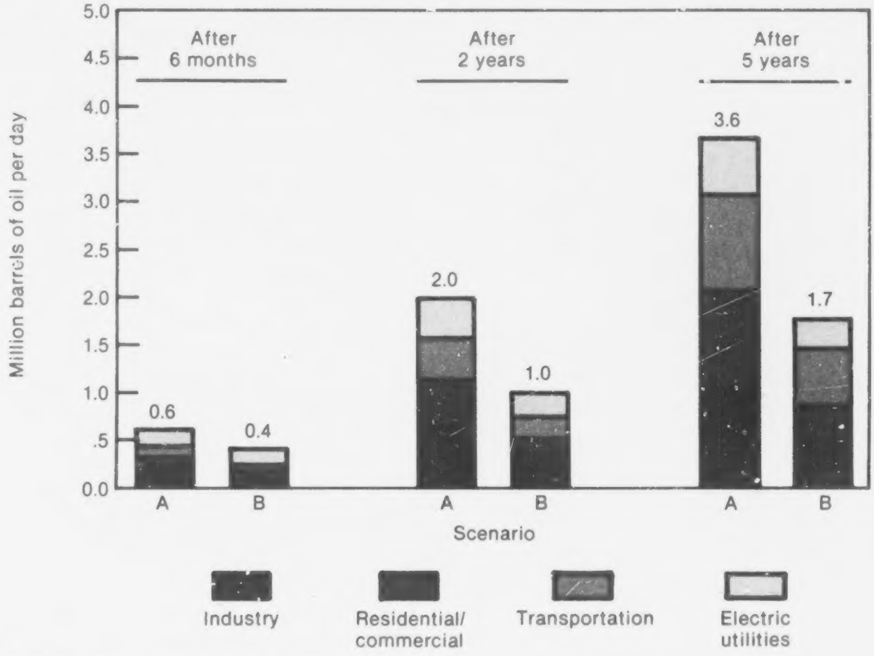
With all of the changes described above, oil replacement could total about 3.6 MMB/D by the end of 5 years; and based on current production capacities and historical high rates of conversion, the replacement might proceed something like that shown in figure 1.

Slower Response—Case B

For the slower response case, OTA assumed that new automobile sales would drop to half the level of the late 1970s and that incremental natural gas supplies would be one-third of the 2 TCF per year assumed in the more optimistic scenario. With these alternative assumptions, the oil replacement in the industrial and residential/commercial sectors would drop by about two-thirds. In the utility sector, however, even with the reduced number of coal conversions and new powerplant completions, there would still be sufficient activity to replace about half of utility oil use (provided demand for electricity does not grow rapidly). Similarly, in the transportation sector, there would still be sufficient replacement of older vehicles by newer, more fuel-efficient models to capture almost two-thirds of the oil savings derived in the more optimistic scenario. Taken together, these changes would reduce the oil replacement at the end of 5 years from 3.6 MMB/D to about 1.7 MMB/D.

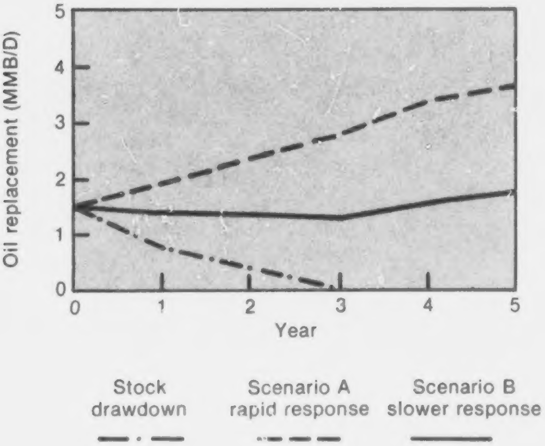
Figure 3 shows the oil replacement by end-use sector for **both** response cases, 6 months, 2 years, and 5 years after the onset of the shortfall. In figure 4, the oil replacement from investment in the replacement technologies is combined with the

Figure 3.—Potential Reductions in Oil Consumption



SOURCE: Office of Technology Assessment

Figure 4.—Potential Oil Replacement



SOURCE: Office of Technology Assessment.

assumed Strategic Petroleum Reserve and private stock drawdown to give two scenarios for the overall potential replacement of oil lost from the short fall, as a function of time.

In all, about 30 percent of the oil that could be replaced in the **rapid response** by the end of 5 years could be attributed directly to increased efficiency in space heating, industrial processes, automobiles, and light trucks. Also, greater efficiency could reduce natural gas use, thereby making more natural gas available to meet the needs of the rapid response case.

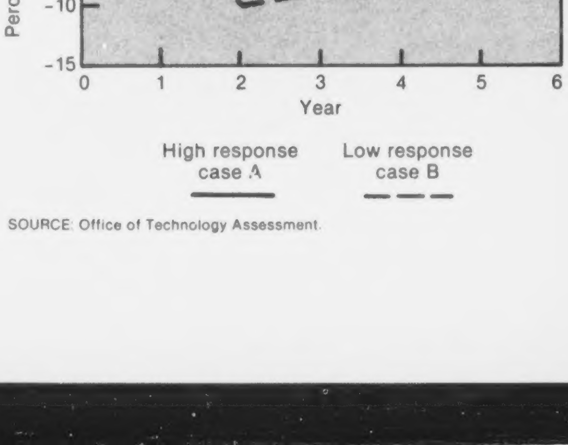
Macroeconomic Impacts

The postulated curtailment of oil imports was simulated using an input/output model of the U.S. economy.[16] While all aspects of such an unprecedented economic shock are difficult to anticipate, the modeling exercise focused primarily on the macroeconomic implications of alternative technological responses. The two 5-year shortfall scenarios, the rapid and the slow response, were simulated in order to bracket the range of technological uncertainties.

Comparisons of the two scenarios suggest that the more rapid rate of investment in oil replacement more effectively limits the losses. The range of possible economic outcomes derived from the model is summarized in figure 5 in terms of GNP behavior.

From the 5-year perspective, the model predicts that the main impact of the shortfall on GNP is a temporary delay in the achievement of long-term output objectives. In the one extreme, case A, the net GNP loss 5 years after the onset of the shortfall (relative to the reference case) could be made up in about a year of normal growth (about 2 percent). In the other extreme, case B, making up the loss would take about 2 years. Although there is a severe recession 2 years after the beginning of the oil import curtailment, this recession is only temporary and the economy rapidly regains most of the loss. In other words, the model suggest that if short-term economic problems can be resolved,[17] the loss of oil im-

Figure 5.—GNP: Two Shortfall Projections Percentage Reductions From Reference Case



SOURCE: Office of Technology Assessment.

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[16] Macroeconomic analysis is based on the INFORUM model (Inter-Industry Forecasting Model of the University of Maryland) of the U.S. economy. It permits detailed accounting for oil flows, prices, capital stocks, and technology deployment for 78 producing sectors as well as associated personal income and consumption, exports and imports, and government activities. OTA calibration of the model was limited primarily to activities directly affected by oil markets, and thus the rest of the economy was taken as it was previously incorporated into the INFORUM model structure. The scope of analysis is also limited to including only a brief treatment of emergency conditions immediately following the disruption shock in order to concentrate on conditions over a 5-year period.

[17] SPR drawdown addresses some of the short-term economic problems, but the economic response also depends on fiscal and monetary policy, speculation, income transfers, and many other factors.

ports should not significantly lower long-term prospects for economic growth.

A second general observation concerns the average loss in the level of GNP over the first 5 years after onset of a shortfall compared to the reference case.[18] **In the rapid response scenario, the permanent loss of oil imports lowers GNP on the average by about 3.5 percent. In the slower response scenario, the average loss is about 6.2 percent. The GNP rebounds toward the end of the 5-year period because investments in oil replacement have reduced the burden of high energy costs on the economy.**

A third comparison (though less important from a longer term perspective) involves year-to-year change in GNP during the first 2 years following the shortfall's beginning. While comparisons between normal growth rates and average output over 5 years are most interesting, given the model used, this shorter term perspective is probably most important for public perceptions of economic hardship. In the slower response scenario, there is considerably less investment in oil replacement technologies than in the rapid response. This leads to a slower pace of oil replacement and increased bidding for the remaining oil supplies. Consequently, the slower response scenario results in a larger oil price rise and greater economic hardship.

Although GNP actually declines only in the second year after the shortfall begins, the decline in case A is only 1.3 percent from the previous year, while it is 5.2 percent in case B. This difference can be appreciated by noting that in the worst recession since the Great Depression, real GNP declined in 1982 by 1.7 percent from that in 1981. The recession just prior to that, from 1979 to 1980, involved only a 0.2 percent decline in GNP. In other words, case A is within recent historical experience; case B is well outside of it.

Besides this overview of the entire economy, the economic situation 5 years after the shortfall begins can also be described in terms of the market clearing price of oil. Market expectations for oil price inflation provide the rationale for investment in oil replacement at the same time as they cause dislocation in industry and loss of consumer purchasing power. In case A, an oil price increase of about 60 percent above its current level would be sufficient to accommodate oil demand to reduced supply. In case B, oil prices must increase by about twice that amount to balance demand with supply.

These price expectations summarize both the technological opportunity set for oil replacement and the behavioral adjustments to higher oil prices which are built into the macroeconomy. Behavioral adjustments include product mix shifts from products with relatively large oil inputs to those with relatively low inputs, adjustments in direct fuel consumption by consumers (mainly by driving less and turning down thermostats), and general restriction of economic activity.

Finally, all of these economic conclusions must be qualified by acknowledging the uncertainties that may not have been treated realistically in the modeling effort. First and most important are emergency responses immediately following the onset of the shortfall. Although the GNP projections shown above included the entire 5-year shortfall period, the actual numbers could be greatly affected by market and political actions that are not closely related to the technological focus of this study. In addition, the oil shortage emergency could trigger inflationary or recessionary spirals that would slow down oil replacement.

On the other hand, the shock of another oil loss could trigger major lifestyle or technological changes that would lower the cost of oil replacement. For example, work and entertainment patterns may be shifted to the home, where rapid advances in communications and computer technologies could significantly reduce the need for auto travel. These were not considered in the economic analysis because primary attention was given to those flexibilities and rigidities in the energy economy that can be predicted from the technology analysis in the assessment and from recent historical experience.

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[18] Please notice that the Model's behavior at the start of the postulated disruption in 1985 is strongly influenced by current expectations that the economy will have considerable growth momentum. If, on the other hand, the United States were mired in recessionary doldrums, the projections could be quite different.

Environmental Impacts

The increased use of solid fuels for the rapid response path (a total of 115 million tons/yr of coal equivalent) will require that coal production be increased by up to 13 percent over 1982 levels, a situation that will entail greater mining-related impacts. About 65 million tons/yr of coal would be used in utility and industrial boilers converted from oil. To avoid increases in sulfur and particulate emissions, these boilers would have to use low-sulfur coal and particulate control systems, for which supplies are adequate for the postulated scenarios. However, there would probably be an increase in nitrogen oxide (NO_x) emissions in some of these boilers; and to the extent that fuels with higher sulfur contents are used in converted boilers (without new scrubbers) sulfur dioxide (SO_2) emissions would also increase.

An additional 35 million tons/yr of coal would be used in new and existing coal-fired utility boilers to replace (mostly distillate) fuel oil used in the residential and commercial sectors. This would also lead to an increase or at least a delay in the reduction (through retiring older boilers) of SO_2 and NO_x emissions. The remaining 15 million tons/yr would be used in new ethanol distilleries. The larger distillery boilers (50 million gal/yr or larger of ethanol production supplied by a single boiler) would be regulated by Federal New Source Performance Standards, but most of the distilleries would probably be regulated primarily by State and local requirements for emission controls.

Production of 5 billion gal/yr of ethanol (which is included in the rapid response and is capable of reducing U.S. oil consumption by about 0.1 MMB/D) would require a 15-percent increase in

Photo credit: U.S. Department of Energy

Coal is surface mined using drag lines and other large mining equipment grain production. This would probably lead to more than a 15-percent increase in soil erosion and the accompanying pesticide and fertilizer runoff because much of the new cropland would be more erosive and less productive than current average cropland used for grain production.

The increased supplies of wood for fuel could be supplied as part of careful forest management programs without significant adverse environmental impacts; but if the wood is harvested in a haphazard manner, damage to the forest and eventually to forestland productivity could be substantial. Furthermore, burning wood without emissions controls (e.g., for home heating) would likely lead to significant local increases in particulate emissions, including higher levels of polynuclear aromatics (which are generally not a problem with either central electric power generation or natural gas or oil combustion). But sulfur emissions from wood would be insignificant.

Longer Term Effects

In the longer term (greater than 5 years), the principal consequences of the rapid response will be inflationary pressures on natural gas and food. If natural gas production falls sharply in the 1990s, the increased dependence brought about by oil replacement will greatly increase natural gas prices and/or imports. But if production capacity remains at current levels or higher, or a slower drop in production is coupled with feasible increases in the efficiency of natural gas use, price pressures will be lower, and a more orderly, long-term transition to increased use of coal, electricity, and renewables can occur. Supplying the grain feedstocks for 5 billion gal/yr of ethanol production will lead to increases in farmland and food prices, and these increases will persist as long as the feedstocks are supplied. On the other hand, if ethanol production is kept below about 2 billion gal/yr, the impact on food prices probably would be relatively small (i.e., less than a 1-percent increase).

Also, the reduction in oil consumption (resulting from the shortfall) and the replacement of oil by nonpetroleum fuels and increased efficiency will accelerate the transition that must occur in the 1990s as domestic oil production drops. And if long leadtime technologies, such as new enhanced oil recovery and synthetic fuel projects, are initiated during the first few years of the shortfall, they would begin to reduce somewhat the liquid fuel shortages in the 1990s. **With the rapid response, the United States could minimize the adverse economic consequences of a large oil shortfall and accelerate many of the changes that will eventually be needed if the United States is not to remain heavily dependent on imported oil. With the slower response, however, the adverse economic effects would be both more severe and longer lasting.**

Finally, **the vulnerability of the U.S. economy to oil supply shortfalls is not likely to decrease in the near- to mid-term future, and it could very well increase.** As domestic oil production declines, U.S. oil imports will increase and/or some of the oil used for space and water heating and steam will be replaced. Increased imports are likely to lead to increased oil production in politically unstable areas of the world, thereby increasing the size of any potential oil shortfall, and reduced use of oil for the most easily substitutable end uses will reduce the quantity of oil that can be replaced quickly. In both cases, U.S. vulnerability will increase.

These trends can be countered somewhat in the mid to long term by relying more heavily on coal and biomass for chemicals production, by increasing transportation fuel efficiency (primarily automobiles and light trucks), and by producing synthetic fuels. The first two actions would reduce the fraction of business costs and personal consumption that is tied to oil prices, thereby reducing the importance of oil prices to the overall functioning of the economy. Domestic synthetic fuels production would reduce the payments for imported oil and together with new sources of conventional oil production in the world, would increase (or at least lower the reduction in) the excess worldwide oil production capacity that can buffer the effect of a sudden drop in world oil supplies. Effecting these changes, however, will require many years. Even if they are pursued vigorously, the United States is likely to remain vulnerable to world oil shortfalls until well after the year 2000.[19]

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[19] See *Increased Automobile Fuel Efficiency and Synthetic Fuels: Alternatives for Reducing Oil Imports*, op. cit.

POLICY

OTA's analysis indicates that the economic damage, such as increased unemployment and lowered GNP, caused by a large oil supply shortfall (or price increase)[20] can be reduced significantly (but not eliminated) by expeditious investment in technologies that replace the lost oil with increased efficiency and alternative domestic fuels. Although a drawdown of the Strategic Petroleum Reserve (SPR) and private oil stocks probably is essential to moderate pressures on the oil markets in the short term, **the effects of investments in oil replacement technologies could easily exceed the importance of stock drawdowns after about 1 year.**[21] And after 2 to 3 years, stocks would most probably be exhausted. Price controls and subsidization of oil imports, such as was done in the mid-1970s, may also be able to moderate the immediate price shock; but the resultant, incorrect price signals, if allowed to persist, could lead to economic inefficiencies that might be more damaging in the long term than those produced by rapid changes in oil prices.

Although OTA has not analyzed the effects of various strategies for oil stock drawdowns or price controls, it is clear that these measures will be most effective if strategies for using them are developed and refined in advance of a supply shortfall. The analysis needed to formulate these strategies may lead to the conclusion that price controls should be rejected; but, at the minimum, a clear plan[22] should be developed for a drawdown of the SPR, in conjunction with deployment of private stocks, if the benefits of the SPR are to be maximized. Furthermore, **any such plans should take into consideration the potential deployment of oil replacement technologies and the effect that various methods of drawdown would have on this deployment.**

Beyond these near-term responses, investments in oil replacement technologies can provide the principal means of easing pressures on oil markets in the mid-term, as well as lowering expectations of future oil price rises (and thus speculation in oil stocks). And these investments (like any other investment in consumer and producer durables) would serve to stimulate the economy and partially counteract the economic downturn resulting from a shortfall. Through these effects, the investments would tend to limit the oil price rise and economic damage.

In the absence of price controls, the large increase in oil prices accompanying the postulated shortfall would provide a strong incentive for oil users to invest in replacement technologies. Nevertheless, investors may be extremely cautious in making long-term capital investments, owing to the economic uncertainties or high capital costs. In either case, the rate of investment in oil replacement technologies could be well below the rate that they can be manufactured and installed. This, together with lowered rates of investment in other consumer and producer durables, would be indicative of a "market failure" that could lead to a recession more severe than that dictated by the magnitude of the shortfall.

A central problem facing policymakers who wish to minimize the potential economic losses from an oil supply shortfall is therefore to: 1) identify the technologies that can replace large quantities of oil at least cost to various oil users, 2) monitor the performance of energy markets and investment patterns for signs of market failure like that described above, and 3) where possible and appropriate, apply incentives to modify the investment behavior. Addressing this problem requires advance preparation in order to establish a functioning system to monitor the appropriate investment behavior and in order to develop the specific procedures and incentives to be used to stimulate investments, if necessary.

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[20] From an economic perspective a price increase is the same as a reduction in supplies. In this sense, both of the supply shortfalls experienced by the United States in the past 11 years have been permanent, since in each case the price of oil remained permanently higher after the shortfall than it had been before the shortfall. While many circumstances surrounding each shortfall are unique, it is not unreasonable to expect that a future supply shortfall could also be permanent in this sense, even if surplus oil production capacity were to develop later.

[21] After 1 year, investment in oil replacement technologies could replace slightly more than 1 MMB/D (million barrels per day) of oil consumption. However, with oil stocks of 700 million barrels and an initial rate of drawdown equal to 1.5 MMB/D, the rate of oil removal from stocks would have dropped to significantly less than 1 MMB/D after 1 year.

[22] The alternative strategies considered should include: 1) offering unlimited quantities of SPR oil (up to the physical maximum rate that it can be delivered) at a predetermined price, and 2) delivering predetermined amounts of SPR oil (based on the size of the shortfall) at the market price. The former approach would tend to put a lid on oil prices (thereby discouraging speculative, private stock formation beyond a certain level, among other things), while the latter would be directed more toward maintaining physical supplies of oil.

A decision to intervene will, of course, be made very difficult by the inevitable uncertainty concerning the duration and direction of an oil supply shortfall and by the enormously complicated tasks of choosing appropriate policy levers to affect investment and coordinating the activities of various institutional and governmental entities with different jurisdictions and objectives. These obstacles are formidable; the argument for intervention, however, rests on the real possibility of market failure and on the very high cost to the country of such failure.

The objective of this study was not to analyze in detail the effectiveness of alternative means of shaping investment choices, but rather to specify the most promising technologies for replacing large quantities of oil within 5 years after the onset of a shortfall and to indicate some of the economic costs and benefits, for the country as a whole, associated with investment strategies that rely on these technologies to different degrees. An analysis of this kind can provide useful guidelines for those who find it prudent to consider policies related to these technologies in planning for, or actually responding to, both the immediate emergency and the longer term problems created by an oil supply shortfall.

With these objectives in mind, the policy analysis outlines a general strategy for identifying and responding to the type of market failure described above and summarizes various other policy concerns directly related to implementing this strategy. In the next section, there is a description of a policy strategy designed to ensure that the potential benefits of deploying oil replacement technologies can be realized. Following this are sections on actions that can be taken in advance to prepare for the possibility of an oil supply shortfall, ways of measuring the rate of investment in the replacement technologies, and a brief discussion of selected regional and international considerations.

Several other policy concerns associated with an oil supply shortfall are not addressed in this report. These include the desirability and potential efficacy of military intervention to secure oil supplies. They also include numerous questions of equity associated with large transfers of wealth within the country and the uneven impact of higher oil prices among the regions of the country and energy-using sectors. And there are questions of priority access to or subsidization of oil supplies to various end uses, such as for home heating, which is crucial to the health of millions of households; agriculture, which is essential to the entire population; and transportation, which binds the economy together.

These are all extremely important questions that will have to be resolved in formulating a comprehensive policy for responding to an oil supply shortfall. In most cases, however, specific decisions regarding these issues would not preclude or obviate the possible need for government intervention to ensure that the potential benefits of deploying technologies to replace the oil lost in a shortfall are actually realized. Indeed, realizing these benefits can lessen some of the concerns mentioned in the above paragraph.

Policy Strategy

The basic hypothesis of this assessment is that the United States suffers a 3 MMB/D reduction in its oil supplies beginning in the mid-1980s and lasting for at least 5 years. One of the first actions the government could take under these circumstances is to begin a drawdown of the SPR[23] in order to help stabilize the oil markets as they adjust to the sudden change in supply. This action would reduce the price rise in the short-term; but as the stocks are depleted, the SPR drawdown would diminish in importance.

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[23] OTA has not examined what would constitute an optimal drawdown of the SPR. For the purposes of the economic modeling, however, OTA has assumed that private and SPR stocks amount to 700 million barrels and that they are drawn down at a rate beginning with 1.5 MMB/D immediately after the onset of the shortfall, with the rate dropping to 0.75 MMB/D after 1 year and 0.38 MMB/D after 2 years. The stocks would then be depleted by the end of 3 years. For additional information on SPR drawdown, see the following publications:

GAO: Strategic Petroleum Reserve: Substantial Progress Made, But Capacity and Oil Quality Concerns Remain, EMD-82-19, December 1981.

Purchase Price of Strategic Petroleum Reserve Oil Fair But Payment Timing is Costly, 1980.

Another action that could be taken immediately is to expedite, where necessary, the processes of issuing State permits under State implementation plans (of the Clean Air Act) for conversions of industrial and utility boilers to coal (e.g., 10 month permitting process). OTA's analysis indicates, however, that these conversions can be achieved within the existing environmental regulations. If low-sulfur coal is used in the converted boilers, together with particulate control devices, and the boilers are properly adjusted for NO_x emissions, the conversions would not lead to increases in regulated emissions or changes in ambient air quality. Consequently, in most cases there should be little regulatory resistance to issuing the needed permits. Similarly, current permitting procedures need not delay the completion and issuing of operating permits and certification for new electric powerplants.[24]

Unresolved social conflicts, however, could delay coal conversions and new powerplant projects by several years or more. The places where this would have the greatest effect on oil replacement would be in electric utilities in New England and the New York/New Jersey area[25] (which consume about 0.3 MMB/D) and in conversions of industrial boilers to coal (total oil replacement potential of 0.2 MMB/D). While this 0.5 MMB/D of potential oil replacement is an important part of the total, it is not essential. Even if a sizable fraction of these projects were blocked, the Nation still could replace the full 3 MMB/D postulated shortfall within 5 years, although more pressure would obviously be put on other types of oil replacement. Nevertheless, it probably is important to expedite any legal actions and still more important to ensure full and effective public participation during permitting so that citizens' concerns can be addressed and potential benefits of conversion explained.

In addition, a related first step could be to institute changes in electric utility rate regulation since current procedures bias against large capital investments. In particular, elimination of the fuel adjustment clause, allowance of construction work in progress, institution of trended original cost accounting for determining rates on converted plants, and the establishment of rates that allow utilities to capture part of the savings obtained from converting to coal are steps that would probably be necessary if utility boiler conversion is to take place beyond that already in progress.[26] These actions would have to take place on the State level but Federal encouragement would help. If the States are unwilling or unable to take action, the Federal Government may have to legislate such changes if they prove necessary. The Public Utility Regulatory Policy Act provides precedent for such Federal action.

Steps to remove remaining price controls on natural gas should also be considered. Such measures would act to stimulate new supplies from old natural gas fields[27] and provide additional incentives for conservation of natural gas. Both would be important in ensuring that the natural gas supplies needed to replace oil lost in the shortfall would be forthcoming, and that they would remain available in the event domestic nat-

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U.S. Strategic Petroleum Reserve at a Turning Point: Management of Cost Oil Supply Problems, and Future Site Development, 1980.
Factors Influencing the Size of the U.S. Strategic Petroleum Reserve, ID-79-8, June 15, 1979.
CBO: Financing Options for the Strategic Petroeum Reserve (Barry J. Holt), April 1981.
CRS: Strategic Petroleum Reserve: Implications for U.S. Foreign and Defense Policy, June 15, 1982.
Strategic Petroleum Reserve, IB81096, Feb. 14, 1984.

[24] See *Nuclear Power in and Age of Uncertainty* (Washington, DC: U.S. Congress, Office of Technology Assessment, OTA-E-216, February 1984).

[25] Electric utilities in other regions of the country either do not use significant amounts of oil or have sufficient capacity additions planned to eliminate their oil consumption and provide sufficient nonoil-fired electricity for residential and commercial conversions to electric space heating and hot water, even if some of the projects are blocked. In the case of high growth in demand for electricity between 1985 and 1990, however, the Mid-Atlantic region and Florida are marginal cases; and significant resistance to conversion and new powerplant projects could leave these regions consuming a few tens of thousands of barrels per day 5 years after the onset of an oil shortfall.

[26] For a more complete discussion of the current state of electric utilities in this country and potential regulatory reform proposals see "Promoting Efficiency in the Electric Utility Sector," Congressional Budget Office, U.S. Congress, Washington, DC, November 1982; and *Nuclear Power in an Age of Uncertainty*, op. cit.

[27] See "Effects of Decontrol on Old Gas Recovery," staff memorandum, Office of Technology Assessment.

ural gas production declined significantly over the 5 years after the onset of the shortfall.

In addition to these measures, Congress may also wish to stimulate investments in oil replacement technologies directly. One strategy for doing this would be to establish (where they do not now exist) the data collection and analysis needed to monitor investments in oil replacement technologies. In the event of an oil shortfall, the monitoring apparatus (see below) could be used to measure investment behavior. Various levels of investment incentives could then be implemented, depending on the rate of investments and other economic measures, such as the price of oil, stability of oil markets (as measured by the rate of change of oil prices and stocks), and unemployment and inflation rates.

A first level of government action could involve dissemination of information designed to inform oil users about their options for replacing oil. This could be accompanied by advertising campaigns and statements by political leaders emphasizing the importance of making investments to replace the lost oil and the economic consequences of not doing so. This could also include public participation in a variety of activities designed to increase public awareness of energy issues and create a favorable attitude toward measures designed to replace oil.

In addition to the first level, a second level of action could include economic incentives. Residential and commercial oil customers could be provided with low-interest loans and/or tax credits for qualifying investments. Sales of inefficient automobiles could be taxed, and subsidies could be placed on the sale of more efficient ones.[28] These incentives could be formulated to be a net subsidy on the purchase of new cars if the volume of new car sales dropped significantly.[29] In addition to the regulatory changes discussed above, loan and interest guarantees could be provided for electric utilities in order to facilitate their access to the capital bond markets. Financial incentives, such as tax credits, could also be provided to the industrial sector for investments in oil replacement, although these have proved to be ineffective at the relatively low levels that have been applied historically.[30]

In addition to (or in place of) the first two levels, the government could regulate some aspects of oil replacement. The largest utility and industrial boilers could be targeted for conversion to coal; and industrial oil efficiency standards (Btu of oil consumed per unit of output) could be applied to various industries. Fuel use and efficiency standards could also be applied to large commercial and apartment buildings. Application of such standards to small businesses and private homes, on the other hand, could be extremely controversial and difficult to enforce. Similarly, attempts to increase the corporate average fuel economy of automobiles and light trucks without 4 to 5 years advance notice would probably prove to be relatively ineffective because of the long leadtimes for product development and acquisition of new capital equipment.[31]

The investment needed to replace 3 MMB/D of oil and, if necessary, to increase the efficiency of natural gas use would be about $150 billion to $200 billion over a 5-year period, or about $30 billion to $40 billion per year, on average (not including the cost of new cars, which is an ongoing activity). This level of investment is about 7 to 9 percent of recent annual investments in producer durables and residential and nonresidential structures. By comparison, OTA estimates that crude oil prices would rise by $23 to $40 per barrel (above a predisruption level of $30 per barrel), increasing domestic oil and natural gas liquids production revenues by $84 billion to $146 billion per year (with domestic production at 10 MMB/D). Consequently, even in the extreme case, where Federal subsidies would pay a large part of these investment costs (and perhaps new cars received subsidies of $1,000 each, on average, or $6 billion to $10 billion per year), these costs could probably be financed through a windfall profits tax, if it were increased to collect 50 to 70 percent of the increased domestic oil production profits.

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[28] This would, however, encourage the sales of smaller cars, a market where U.S. manufacturers have not been strong competitors in the U.S. market. It would also amount to a net subsidy to auto companies that only sell small cars.

[29] Keeping new car sales volumes up is nearly as important as encouraging higher new car average fuel efficiency, because even the less efficient new cars are significantly more fuel efficient than the corresponding average car on the road. (For further discussion see *Increased Automobile Fuel Efficiency and Synthetic Fuels: Alternatives for Reducing Oil Imports*, op. cit.

[30] See *Industrial Energy Use* (Washington, DC: U.S. Congress, Office of Technology Assessment, OTA-E-198, June 1983).

[31] Obviously, new car fuel efficiency would increase following the oil shortfall, but it would primarily be the result of demand shifts to more efficient cars already in production and introduction of new models that were in the development stage prior to the shortfall.

An overall strategy then might consist of establishing the investment monitoring system and contingent incentives and taxes in advance. In the event of a shortfall, the first level of incentive could be implemented immediately. If, after 6 months to 1 year, investments appeared to be proceeding too slowly and other economic measures appeared to favor market intervention,[32] the second level could be introduced, and the financial incentives could be increased if they proved not to be sufficiently effective. The third level of incentives could then be introduced if the response to the two previous levels were judged to be inadequate.

The advantage of this strategy is that it provides a flexible and well-defined government response that can be adjusted, depending on the market behavior and the response to various levels of incentives. With the monitoring system, which examines each sector individually, there is also the ability to apply different levels (as well as different types) of incentives to different sectors and to identify and correct any significant sector-specific constraints (e.g., certification delays for new powerplants). A possible disadvantage is that investors may delay investments in anticipation of future government subsidies such as occurred in the 1970s with respect to the purchase of home insulation. If this is judged to be a significant problem, however, provisions could be included to make any subsidies effective retroactively to the onset of the shortfall, thereby reducing the speculative value in delaying investments (unless large groups of investors act in concert to trigger a subsidy that might otherwise not have been needed).

Beyond the short- to mid-term oil replacement options, an oil shortfall is likely to renew interests in the longer term options, such as further increases in corporate average fuel economy standards for new cars and synthetic fuels production. Although these options would have little impact on liquid fuel supplies until well over 5 years after the onset of a shortfall, they could contribute to moderating liquid fuel prices in the 1990s when conventional domestic production of both oil and natural gas is likely to decline. To be effective in promoting these options, however, government policies would have to show a stable commitment over a period of a decade or more.

Advance Preparation for an Oil Supply Shortfall

One government response to the threat of a future oil supply shortfall is to promote investments in a wide variety of oil replacement technologies in order to put downward pressure on oil prices and increase worldwide surplus oil production capacity. This reduces the risk of a severe supply shortfall. However, some of these technologies require long leadtimes and therefore are of little use in preparing for the possibility of a shortfall in the near future. Furthermore, this strategy cannot contribute to a quick response if and when a shortfall materializes.

It has been suggested that one way to reduce the response time is to construct and stockpile any oil replacement equipment that might be in short supply following the disruption. Since the time needed to convert an individual facility or building away from oil is less than about 2 years for all of the technologies included in OTA's replacement scenarios, stockpiling could theoretically reduce the time needed to replace the oil significantly.

OTA's analysis, however, indicates that, in most cases, the equipment that would have to be stockpiled represents a sizable fraction of the total investment needed for the complete conversion away from oil. (Conversely, any equipment that is not expensive generally is relatively easy to produce, and production capacity for it can be expanded rapidly.) Consequently, it would generally be more cost effective to make the additional investment needed to complete the conversion and then use the equipment to reduce fuel costs, rather than to allow the equipment to stand idle in a stockpile.

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[32] For example, if: 1) investment in oil replacement technologies were low, 2) unemployment were rising, and 3) the economy were stagnating, then investment incentives would probably be appropriate. High inflation beyond that caused by rising oil prices, on the other hand, would tend to speak against market stimulation. And if the economy, oil markets, and employment appeared to be stable then, even if investments in oil replacement technologies were low, government intervention to stimulate these investments might not be necessary.

In some cases (e.g., conversion of large boilers to coal), a limiting factor could be the number and capacity of experienced architecture and engineering firms capable of designing and carrying out the conversion. Increasing the capacity for these conversions would involve increasing the pool of trained manpower; and, in the absence of immediate job opportunities, this could prove to be difficult and costly.

A number of other actions, however, can be taken in advance to increase the ability to respond to a large oil supply shortfall. But most of these fall into the categories of advance planning and information, rather than hardware acquisition.

A monitoring system needed to measure the rate of investment in oil replacement technologies should be established well in advance of a shortfall to provide operating experience and a historical data set in order to assess better the information collected following onset of a shortfall. The details of the various levels of investment incentives, including specific procedures, responsibilities, and implementation plans, should also be established in advance so that incentives can be implemented quickly and smoothly when needed.

Surveys of boilers where coal conversions are most likely should be kept current; information about potential coal storage sites, coal transportation capabilities, and possible local shortages in skilled labor should be developed; and the information should be made available to assist private and government planning at all levels. Plans for technical assistance could be developed to help large oil users find coal storage sites and transportation for low-sulfur coal and to aid them in the mechanics of obtaining the necessary permits for coal conversions.

Information could also be provided to increase the public's awareness that investments in fuel switching and increased efficiency of energy use, following a large oil supply shortfall, will reduce the adverse economic effects of the shortfall and that these measures can be implemented within the existing environmental regulations. This would encourage investment in the whole range of oil replacement technologies and would increase the public acceptance of, or minimize the resistance to, possible government intervention and other activities needed for oil replacement following a shortfall.

Finally, an important pre-shortfall step might be to undertake the electric utility regulatory and natural gas pricing changes suggested above. Such actions would provide an incentive for utilities to convert existing natural gas boilers to coal at an accelerated rate. Nearly two-thirds of these existing boilers are uneconomic at today's oil and natural gas prices but continue to operate partly because of the current regulatory climate.[33] As discussed previously, the gas pricing changes would bring about additional supplies, and consumers would be able to make decisions about their use of gas based on prices closer to the replacement value. All of these actions would stimulate oil replacement in any event, and, in case of a shortfall, would be in place and operating to help ensure adequate gas supplies for the rapid response.

For these measures to be most effective, there would have to be a commitment, as a matter of government policy, to intervene to promote investment in oil replacement technologies if the market response is overly cautious. However, with this commitment, the ability to measure the relevant investment behavior, and the mechanisms to apply successively stronger incentives, it seems likely that the potential benefits of rapidly deploying the oil replacement technologies could be realized.

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[33] See "Promoting Efficiency in the Electric Utility Sector," Congressional Budget Office, op. cit.

Even in the absence of a supply shortfall in the mid-1980s, the long-term trend is toward reduced use of oil for fuel in stationary applications. As this trend continues, most of the technologies emphasized in this report will become increasingly ineffective as cushions against an oil supply shortfall. The principal remaining uses of oil will be for transportation and materials (e.g., chemicals), and U.S. oil replacement capability will increasingly be determined by the speed with which oil substitutes can be deployed in these sectors.

Although the leadtimes for replacing large quantities of oil in these end uses are likely to remain long, the ability to respond in these areas to an oil supply shortfall could be increased somewhat through research and development (R&D). For example, development and standardization of designs for mobile gasifiers[34] adapted to modern vehicles could provide a device that could be easily and rapidly manufactured in large quantities to replace the fuels used in cars, trucks, buses, and other surface vehicles, although the potential market for these devices is highly uncertain. Development of small (e.g., less than 10 million gal/yr), prefabricated synfuel plants for converting solids, probably solid biomass,[35] into methanol or gasoline,[36] might enable a rapid deployment of these plants to produce gasoline substitutes without the inflationary effect on food prices associated with ethanol production. Continued R&D into chemical feedstocks from plants and solid fuels and more efficient chemical manufacturing processes can also increase the options for reduced oil consumption in the chemical industry. And continued development and manufacturing of increasingly more fuel-efficient vehicles will enable consumers to purchase these vehicles in larger numbers in the first few years following a large oil price rise than would be the case if these efforts stagnate.

Even if successfully developed, the 5-year oil replacement capability of these options is likely to be considerably smaller than that associated with the technologies considered in detail in this report. Nevertheless, continued R&D of oil and natural gas substitutes provides an important means of countering the long-term trends toward increasingly tight supplies of these fuels and therefore provides an important means of reducing the probable magnitude and severity of an oil supply shortfall that may occur further away in time.

Measuring the Rate of Oil Replacement

Owing to the uncertainties about the investment rates in oil replacement technologies that would occur with a free market response and with various levels of market intervention by the government, it is important to have measures of the rates and types of investment that occur to see if intervention is necessary to increase the rate of oil replacement and, if so, to help determine the minimum level of intervention needed. As described below, some of the investment rates can be determined from data currently being collected, while the measurement of others will require additional data collection and/or analysis. All rate determinations will require continual and prompt[37] updating and evaluation of the relevant data if they are to be of maximum use in policy decisions. And the data collection and analyses should be carried out in a manner that is designed and intended for determining oil replacement rates through investment in energy technologies.

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[34] Mobile gasifiers are devices that are carried on board cars, trucks, buses, and other vehicles and that convert solid fuels into fuel gases that can be used to fuel the vehicle. See also the section on technologies in ch. IV.

[35] Solid biomass (wood grasses and crop residues) may be a more economic feedstock for small synfuel plants than coal is, because the former does not require an oxygen plant owing to the higher oxygen and hydrogen content of the biomass. Whether this will prove to be a decisive economic advantage remains to be seen, however.

[36] For a rapid response, gasoline production may be preferred to methanol production because the latter (if used in large quantities) would require retrofitting of vehicles or the manufacture of new vehicles designed for methanol. However, since OTA has not assessed the constraints associated with deploying prefabricated synfuel plants or increasing the availability of methanol-compatible vehicles, it is unclear which of these would be the limiting factor. If the fuel supply were limiting, supplies could be supplemented with the surplus production capacity of methanol from natural gas (perhaps 0.05 MMB/D oil equivalent in the United States). However, unless this methanol is imported, it may be preferable to use the (domestic) natural gas in the vehicles directly, since more miles could be driven per unit of natural gas consumed if it is used directly. On the other hand, future developments that increase the efficiency of methanol-fueled engines could more than overcome the energy loss of converting natural gas to methanol. Current indications are that methanol or gasoline could be produced from solid biomass at lower prices (per unit energy) than ethanol.

The rate of increase in the fuel efficiency of cars on the road can be conveniently monitored using the data currently being collected on new car sales, new car average fuel efficiency, and scrappage rates, provided the results are made known in a timely manner. Similarly, considerable data already exists on utility boilers and new powerplants under construction; and the number of these boilers and new powerplants is sufficiently small that they can be monitored on an individual basis.

Monitoring industrial oil use, involving about 4,000 large[38] boilers, over 140,000 smaller boilers, and numerous varied industrial processes, would require ongoing surveys[39] of manufacturers.[40] Surveys similar to those needed have been conducted in the past by the Department of Commerce, with funds from the Department of Energy.[41] Although these surveys were recently discontinued, they or similar surveys could be reinstated with modifications[42] to provide the information necessary to monitor oil replacement investments in industry. Some of these data could also be cross-checked with data on deliveries of various types of equipment, new natural gas hookups to existing industrial facilities, and orders received by architecture and engineering firms for conversions of large oil-fired boilers to coal.

A variety of measures can be used to follow the investment in oil replacement technologies by the 18 million residential and commercial oil customers. The companies that deliver fuel oil, kerosene, and liquefied petroleum gas to these customers could report changes in the number of customers (to indicate fuel switching) and changes in the fuel use per heating degree day. (They already collect the latter data so that they know when to refill customers' tanks.) Gas and electric utilities, that have special rates for space heating customers, could report the number of customers in existing buildings switching to these energy sources for space heating (i.e., exclusive of new buildings). Other gas and electric utilities could report the number of existing customers that have shown large increases in their use of these energy sources (indicating fuel switching) and the number that have had new delivery lines installed to increase the capacity. Data could be compiled on changes in the number of gas furnaces and electric heat pumps sold for space heating. And all of these data could be augmented with surveys of small, statistically representative samples of residential and commercial oil customers. This information could then be combined to give estimates of the rates of investment in oil replacement technologies, and the estimates could be cross checked with data on regional consumption of fuels and electricity by these sectors.

With these types of reporting systems and experience in collecting and analyzing the data, reasonable estimates of the general trends and magnitudes of oil replacement through investment in the major oil replacement technologies could be provided on a continuing basis.

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[37] Quarterly reporting of the data would probably be adequate.

[38] Greater than 50 MMBtu/hr capacity.

[39] Simply monitoring gross industrial energy consumption would not provide sufficient data to distinguish between increased efficiency of oil use and switching to natural gas, on the one hand, and the closing of oil-consuming manufacturing facilities, on the other. For example, increased efficiency of gas use coupled with switching from oil to gas could reduce oil consumption, while leaving gross industrial gas consumption unchanged. These types of ambiguities could not be fully resolved by applying measures of manufacturing output, unless there were detailed information about the fuel use of the manufacturers that are expanding or contracting output. Furthermore, there are seasonal and annual fluctuations in industrial fuel use that could mask the overall trends.

[40] The oil replacement potential in mining (not including oil refining), agriculture, and construction, which are the other parts of the industrial sector, is limited and these subsectors would not need to be surveyed.

[41] Under the title "Annual Survey of Manufacturers: Fuels and Electric Energy Consumed."

[42] For example, the surveys should include fuel that is not bought and sold as well as that which is; it should give the production output of various industrial subsectors and the fuel use per unit of product output; and it should provide information on fuel switching capability that is in place.

Selected Regional and International Considerations

As mentioned above, the reduction in oil consumption that is not replaced through investment in oil replacement technologies must be accounted for by reduced economic activity and personal consumption (of oil as well as other commodities and services). The principal market mechanism through which this interaction is effected is the price of oil. And one difference between the slower and faster rates of investment is that, in the former case, the oil price rises to a higher level in order to drive down economic activity and personal consumption to a lower level.

Although there will be some regional and local price differences and temporal fluctuations in these differences, the larger trends and changes in the price of oil should be felt roughly uniformly throughout the country. Consequently decisions to invest or not invest in oil replacement technologies in a given region will not only affect the price of oil locally but also nationally; and these decisions will affect the (local) price of oil less than they would have done if the region were partially isolated from the national oil markets.[43] However, the burden of making the investments (if they prove to be a burden[44]) will not be spread uniformly throughout the country because the total oil replacement potential, the relative replacement potential in the various sectors, and the relative amounts of various types of investments needed all vary from region to region.

For these reasons, a coordinated national policy may be preferred to a series of independent local and regional policies so that some of the burdens can be shared more evenly and the national nature of many of the impacts can be incorporated more easily into policy decisions. Furthermore, in order to maximize oil replacement, it is necessary that every energy sector invest in replacement technologies as rapidly as practicable. National policy bodies may be better able to resist regionally powerful interest groups seeking exemptions, prohibitions, or special treatment that could lead to lower rates of investment.

To a certain extent the United States as a country is in a similar position, relative to the rest of the world, that a region of the country is in, relative to the United States as a whole. Unless the United States is willing to isolate its oil markets partially from world markets, as was done with price controls and entitlements programs in the mid-1970s, the international price of oil will essentially equal U.S. oil prices. Although the United States uses about one-third of the oil consumed by non-Communist countries in the world (and therefore changes in U.S. consumption have considerable influence over the international price of oil), the impacts in the United States of an oil shortfall will still depend partly on actions of other countries. The international price of oil and the health of other countries' economies (and thus their trade with the United States) will be influenced, among other things, by the extent to which they also are willing to invest in oil replacement technologies.

Although OTA has not analyzed the international aspects of this problem in detail, it is clear that actions at the national level will be needed to influence the behavior of other countries in a direction that is consistent with U.S. interests; and the existence and use of a strong national policy for reducing U.S. oil consumption will improve the bargaining position, persuasiveness, and influence of the United States in any such international interactions.

Furthermore, the International Energy Agreement (IEA), to which the United States is a party, states that "Each Participating Country shall at all times have ready a program of contingent oil demand restraint measures enabling it to reduce its rate of final consumption . . . " or it " . . . may substitute for demand restraint measures use of emergency reserves held in excess of its emergency reserve commitment . . . "[45] Currently, the U.S. "emergency reserve commitments" are

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[43] Because the oil replaced by a given investment will be a larger percentage of local oil consumption than of national oil consumption and the investment therefore will have a greater effect on local supplies than on national supplies of oil, unless the two oil markets are strongly coupled.

[44] Obviously, if the investments do not prove to be a burden, incentives to increase the rate of investment will not be needed.

[45] "Agreement on an International Energy Program (as amended to 19th May, 1980)," Articles 5 and 16, International Energy Agency.

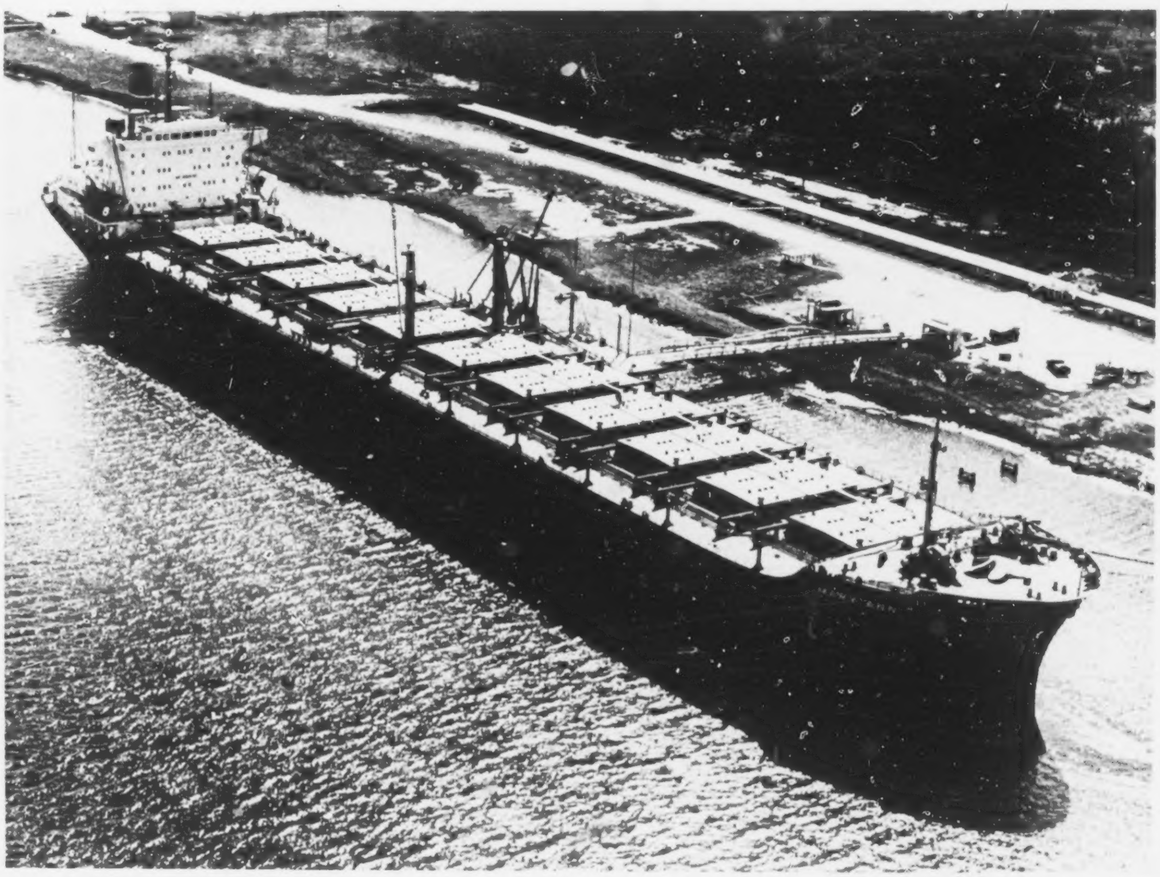

Photo credit: U.S. Department of Energy

Oil is unloaded at this Texas terminal for storage in the Strategic Petroleum Reserve

about 400 million to 450 million barrels,[46] which is roughly equal to mid-1984 SPR stocks. Consequently, current "excess" reserves are equal to private oil stocks that can be drawn down. Since the normal market behavior during periods of rising oil prices is to increase private oil stocks, the "excess" reserves may, in effect, be negative for several months after the onset of a shortfall. The tendency to increase private stocks could be countered through a more rapid drawdown of the SPR following a small oil shortfall, but that response would probably be inadequate following the large shortfall considered in this study. And to the extent that the United States appears not to fulfill this part of the IEA, other channels of international cooperation could also be partially compromised.

Finally, the quantity of SPR stocks needed to provide a credible level of "excess" reserves clearly depends on the fraction of the "demand restraint" that relies on these reserves. A national policy designed to ensure that a more rapid rate of oil replacement can be achieved would not only reduce the level (and cost) of reserves needed to ensure compliance with the IEA but it would also enable the United States to achieve that level at an earlier date. For example, with the supply shortfall and oil replacement scenarios considered in this report, the IEA requirement for demand restrain and "excess" stock use (1.6 MMB/D) would require total "excess" stocks of 980 million barrels for the slow oil replacement scenario and 420 million barrels for the rapid oil replacement scenario. The difference, 560 million barrels, would cost about $17 billion (at $30 per barrel) and take about 3 years to acquire at the early 1984 SPR fill rate.

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[46] Emergency reserve commitment is 90 days supply of net imports. In 1983, net U.S. imports were 4.3 MMB/D and they may exceed 5 MMB/D in 1984.

Chapter III

U.S. Energy Consumption Patterns, 1952-82

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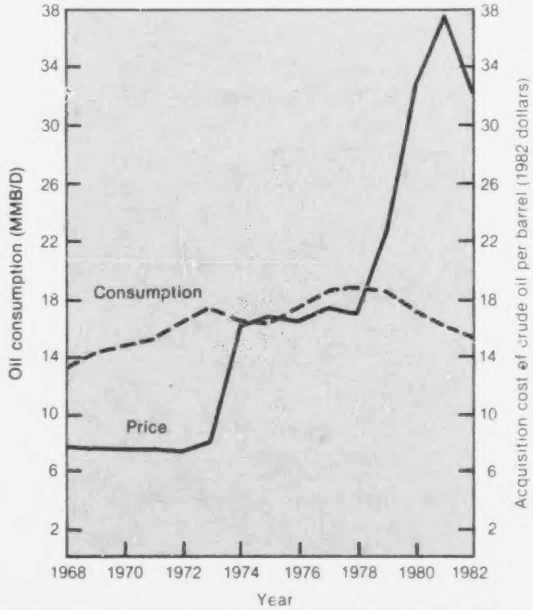
Chapter III

U.S. Energy Consumption Patterns, 1952-82

During the past decade, U.S. energy use changed considerably in response to a series of fuel supply shocks and reversals in energy supply/cost trends. By far, the most important fuel supply shocks involved oil imports. The first of two import disruptions occurred in 1973-74 as a result of the Arab-Israeli war. The second occurred in 1979-80 as a result of the Iranian revolution.

Both shocks had long-term effects on oil markets, effects that preview the expected consequences from a possible third disruption in the future. These effects on oil prices and total oil use over time are summarized in figure 6. As shown, average refiner acquisition prices more or less doubled during each disruption, and total oil use peaked.[1] Two years after the Arab oil embargo of 1973-74, total U.S. oil use had dropped to about 1 million barrels per day (MMB/D) below its 1973 peak. After the initial shock of the second oil disruption, total oil consumption declined for 4 years. In 1982, U.S. oil demand was more than 3 MMB/D below its all-time high of 18.8 MMB/D in 1978.

Figure 6.—Total Oil Consumption (MMB/D) and Price per Barrel (1982 dollars)



SOURCE: Energy Information Administration, *1982 Annual Review of Energy*, Washington, DC, April 1983, pp. 67, 91.

In addition to oil import disruptions, U.S. energy use has also been affected in the last decade by a series of events involving economic adjustments related to energy supply/cost trends. These include the longest coal miners' strike in U.S. history; a reversal in natural gas production, which had been rising rapidly during the 1960s; a reversal in the cost of electricity, which had been declining for decades; the introduction of Federal and State environmental quality standards; and a dramatic shift in the financial cost of capital in 1979. Although the 1977-78 coal miners' strike, which lasted 109 days, may have had only temporary significance in terms of disrupting supplies, it boosted oil use during the period just prior to the Iranian revolution and thus increased oil demand at a crucial time. The other four economic adjustments deserve more attention because they continue to influence energy markets, as well as the potential flexibility of market responses to future oil import curtailments.

In 1972, domestic natural gas production hit a peak, after rising steadily since World War II (see fig. 7). The decline in total production resulted from a depletion of natural resources and from Federal price regulation, which held prices below the rising costs of producing gas from new reserves. At the same time, demand was expanding rapidly because gas is a good substitute for oil used in stationary heating applications, because gas can meet environmental emission standards at relatively low capital costs, and because the price of gas was held down by regulations while the price of oil rose sharply.

At about the same time that natural gas production peaked, the price of electricity sold by utilities bottomed out after decades of steady decline and began to rise during the 1970s (see fig. 8). This reversal resulted from several factors, in-

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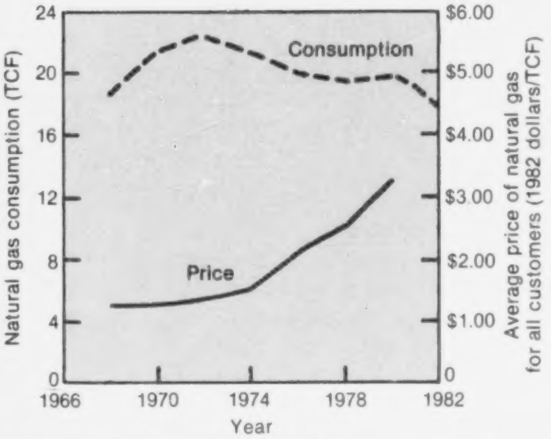
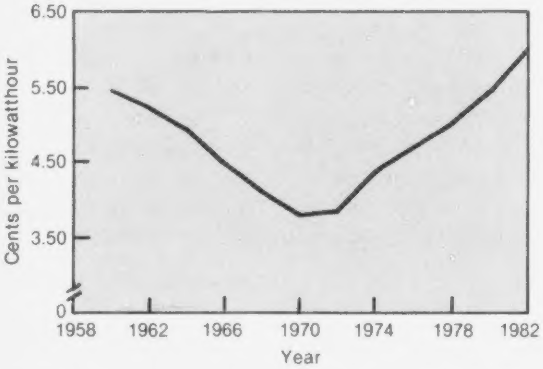
[1] The price of imported oil actually tripled during the 1973-74 curtailment, but the net effect on prices paid by refiners was reduced by the blending of imports with domestic production. Prior to 1973, domestic prices were much higher than import prices, and after 1973, domestic prices were temporarily held below international prices.

Figure 7.—Total Natural Gas Consumption (TCF/yr) and Average Price (1982 dollars/TCF)



SOURCE: Energy Information Administration, *1982 Annual Review of Energy*, Washington, DC, April 1983, pp. 107, 117.

Figure 8.—Average Price of Electricity Sold by Electric Utilities, 1960-82



SOURCE: Energy Information Administration, *1982 Annual Review of Energy*, Washington, DC, April 1983, p. 165.

cluding rising fuel costs, rising costs of meeting environmental regulations, and the rising cost of capital. In addition, during this period there were few technological advances to maintain or lower the capital cost per kilowatthour of generating capacity and/or to reduce the Btu input of fuel per kilowatthour of electricity produced.

Furthermore, the introduction of national environmental quality standards affected energy use during the past decade. The Clean Air Act and Amendments established a national system of air quality regulation, which included ambient air quality and prevention of significant deterioration standards. Partly because of these emissions standards and the uncertainty about future standards, many opportunities for switching to coal, which appeared economic on the basis of fuel costs alone, have not been pursued. Other reasons why switching to coal may not have been cost effective include the costs of conversion, handling equipment, transportation, and storage. Even today, coal still appears to be too bothersome and unreliable to handle and burn for any but the largest installations.

Finally, in 1979, a sharp increase in interest rates limited the growth potential for the entire economy and made it more difficult to reduce U.S. economic dependence on oil. Both of these economic limitations arose because the high cost of capital reduced the level of investment, decreased employment and worker productivity, and slowed improvements in energy efficiency and conversions to less expensive fuels. The high cost of capital particularly constrained growth in the electric utilities industry, which produces the most capital-intensive energy commodity, and made conversions from oil to coal extremely expensive.

This chapter discusses in detail how energy use patterns have changed during the past decade as a result of these developments, with particular emphasis given to oil and natural gas. Natural gas is examined in nearly as much detail as oil because it is an exceptionally good oil substitute for all stationary heat and power applications, provided the user can connect to a distribution pipeline.[2] Together, oil and gas are considered the premium fossil fuels.

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[2] In fact, gas is the preferred fuel in many small burners, such as those in the home, where it can be delivered by pipeline instead of by truck and where it burns more cleanly than oil. Furthermore, gas offers superior flame control in process heating and is the least costly source of hydrogen. However, as a gaseous fuel with a low-energy density per unit volume, it is inferior to oil as a transportation fuel because so little of it (measured in Btu) can be stored in a tank in between fillups.

ENERGY CONSUMPTION AND INTENSITY AVERAGED OVER THE ENTIRE U.S. ECONOMY[3]

Prior to 1974, total U.S. energy use grew in step with the economy. Total energy use increased in every year for 20 years after 1952 except two, when minor declines occurred during economic recessions (1954 and 1958) (see fig. 9). The ratio of Btu per dollar of gross national product (GNP) stayed within a narrow band centered around 59,000 (see fig. 10).

From 1952 to 1972, oil and natural gas accounted for nearly all (97 percent) of the increase in total energy use.[4] Until 1970, gas grew at a much higher rate than oil because of the rapid expansion of transmission and distribution lines built during World War II and because of the huge inventory of gas reserves discovered during oil exploration in the first four decades of this century.

However, all of these trends changed in the early 1970s. Total energy use declined in 1974 and 1975 (see fig. 10). After 2 years of significant decline, total energy use bounced back in 1976 and 1977 and increased in 1979, reaching the most recent peak at just under 79 quadrillion Btu (quads).[5] Since then, total energy use has declined on the average by more than 2.7 percent per year through 1983.

Since 1973, oil and gas use has followed a similar pattern. The upward trend in oil use reversed itself after the Arab oil embargo of 1973-74. It should not be surprising that the upward and downward movements in total energy use and premium fossil fuel consumption would be similar, since the latter accounts for most of the total. It is also worth noting that the premium fuel share in total energy has steadily declined from a peak of 78 percent in 1972 to 67 percent in 1983.

Beginning in the early 1970s, a dramatic change occurred in the growth rates for oil and gas relative to the GNP. Before 1970, use of both premium fossil fuels grew more rapidly than the GNP, as shown in figure 11. Since 1973, both

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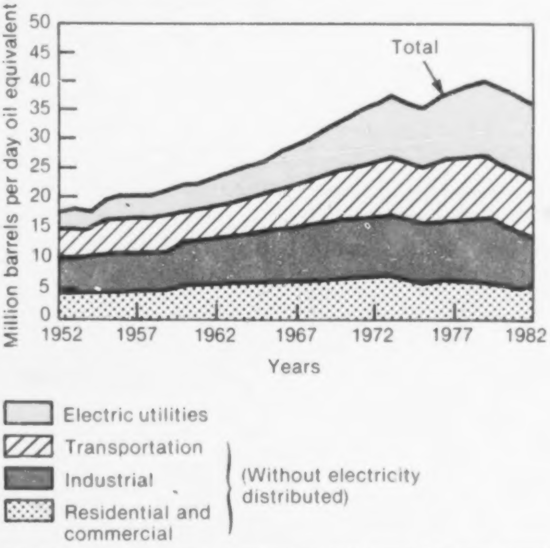
[3] The primary source of data for this and the next three sections is the *1982 Annual Review of Energy*, EIA/DOE.

[4] The increased demand for coal for electricity production was more than offset by the decline in the direct use of coal in the industrial and transportation sectors.

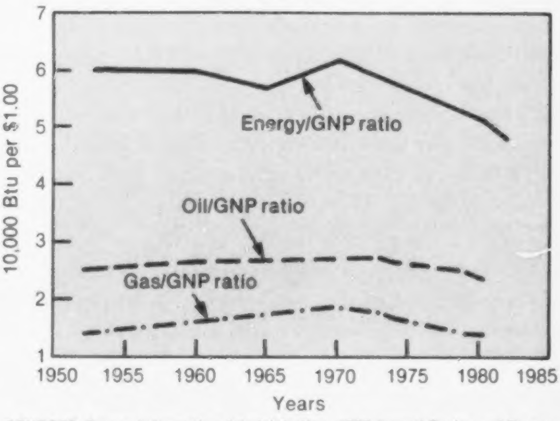
[5] One quad = 1 quadrillion (10^{15}) Btu.

Figure 9.—Consumption of Energy by End-Use Sector



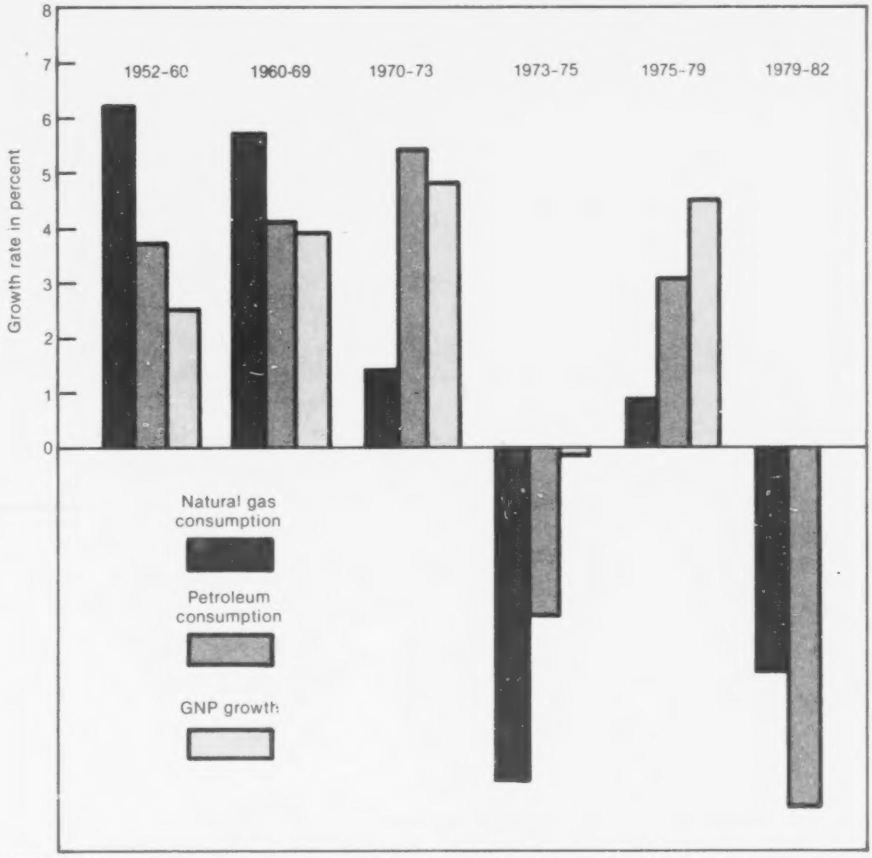
SOURCE: Energy Information Administration, *1982 Annual Review of Energy*, Washington, DC, April 1983, p. 8.

Figure 10.—Energy Consumption-GNP Ratios, 1962-82



SOURCES: Energy Information Administration, *1982 Annual Review, of Energy* Washington, DC, April 1983; Department of Commerce, *Survey of Current Business*, March 1984; Bureau of the Census, *Statistical Abstract of the United States 1983*, Washington, DC, 1983.

Figure 11.—Energy Use and GNP Growth Rate Trends, 1952-82



SOURCES: National Income and Product Accounts of the U.S. Department of Commerce, Bureau of Economic Analysis, September 1981; and Energy Information Administration, *1982 Annual Review of Energy*, Washington, DC, April 1983.

rates have either grown more slowly or, when GNP decreased, declined more rapidly than the GNP. As measured by the ratio of fuel used to economic activity, oil peaked in 1973 at 27,000 Btu per dollar and declined steadily to 19,800 Btu per dollar in 1983. Natural gas peaked at 14,000 Btu per dollar in 1970 and declined to 11,300 Btu per dollar in 1983.

The major reason for these changes in fuel use was rapidly increasing prices, after taking general inflation into account. Figure 6 shows that since 1972, oil prices more than quadrupled and natural gas prices almost tripled. These enormous increases motivated all premium fossil fuel users to reduce their consumption. The price increases also gave domestic oil and gas producers strong new incentives to increase exploration and production. The domestic natural resource base has not increased significantly, however, and domestic oil production has declined since 1970, except for the addition of Alaskan oil. Domestic natural gas production also dropped below its 1973 peak, although the actual decline in production capacity is somewhat obscured by current uncertainties associated with Federal price regulation and possible deregulation.

ENERGY CONSUMPTION BY END-USE SECTOR

Using conventional energy accounts, total energy use can be divided into five sectors: 1) residential; 2) commercial; 3) industrial; 4) transportation; and 5) electric utilities. Residential and commercial energy use figures are often combined because data are not collected separately for all fuels. Fuel use data for electric utilities are also folded into total energy use by the other sectors because electricity is valued in the economy only as an intermediate input into the consuming/producing activities associated with the other four divisions. What is commonly called the industrial sector includes the activities of manufacturing, mining, construction, and agriculture.

Data are gathered for all five sectors, when possible, because each has a distinctive economic objective (e.g., residential, commercial, and industrial) or engages in a distinctive activity (e.g., transportation and electric utilities). Furthermore, with the exception of the transportation sector, each sector comprises a different group of decisionmakers with different economic problems. The combination of distinctive objectives and problems means that the sectors may follow trend lines distinct from one another as the economy grows and contracts over time.

All Fuel Products

When separated, electric utility fuel use displays by far the strongest growth trend, increasing by almost 500 percent and doubling its share over 30 years (see fig. 9). All sectors generally increased their energy use from 1952 to 1972, although industrial consumption declined somewhat during the recession years, particularly 1954 and 1958.

During the next 10 years (through 1982), residential/commercial energy use (excluding electricity) declined by about 20 percent, and industrial consumption declined by about 22 percent. Measured in terms of share in total fuel use, the residential/commercial sectors declined more than 3 percentage points during the last 10 years, compared to a 2-percentage-point decline during the 1952-72 period. The industrial sector share declined by 7 percentage points during the last 10 years, compared to a decline of 8 points during the previous 20 years. From 1972 to 1982, electric power generation increased its share by 8 percentage points and transportation increased its share by about 2 points.

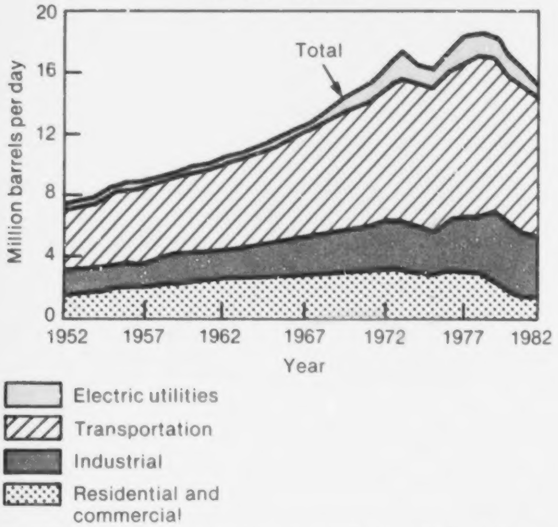
When electricity fuel use data are folded into totals (at 10,000 Btu per kilowatthour [kWh]) for the three end-use sectors, the trend for the residential/commercial share is reversed. Instead of declining during the 30-year period, the share rose steadily, and actual energy use stayed relatively stable after 1974. Electrification, in other words, was of major importance. In the industrial sector, the addition of electricity made only minor changes in both share and actual use trends. There was still a long-term, steady decline in the industrial share of total energy and a significant decline in actual consumption over the last 10 years. In fact, no long-term trend in shares of energy use by sector was reversed during the past decade of oil price inflation and other energy market turmoil.

Oil Consumption

As shown in figure 12, oil use in all four sectors grew steadily prior to 1973. The electric utilities sector experienced the most rapid increase, growing by an average annual rate of about 10 percent and more than tripling its share of total oil use over the 20-year reporting period. Oil use by the residential/commercial sector grew most slowly over the same period, showing an average annual growth rate of about 3.2 percent. Industrial sector oil use grew at about 3.7 percent per year, while transportation sector use grew at the rate of 4 percent annually.

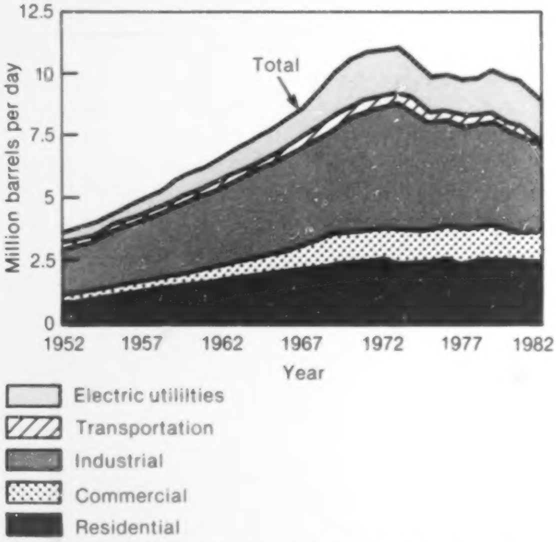
Since 1973, oil use has been shifting to the transportation sector. The industrial sector has maintained its share in total oil use in the last decade, principally because nonfuel use of oil—e.g., as a raw material—has grown, offsetting the decline in fuel applications. In contrast, the residential/commercial sector continued to lose its share of total oil use, and at a rate faster than that exhibited in the previous 20 years. Finally, after holding its total use and its share of total oil use

Figure 12.—Refined Petroleum Products Supplied to End-Use Sectors



SOURCE: Energy Information Administration, *1982 Annual Review of Energy*, Washington, DC, April 1983, p. 66.

Figure 13.—Consumption of Natural Gas by End-Use Sector



SOURCE: Energy Information Administration, *1982 Annual Review of Energy*, Washington, DC, April 1983, p. 106.

constant until 1978, electric utilities have since lowered both sharply.

Natural Gas

Natural gas use data are available for all five end-use sectors. However, only four sectors show significant trends (see fig. 13). In the transportation sector, gas use has remained constant at 3 percent of the total since 1952 because it is used almost exclusively as a fuel for pipelines. The other four sectors steadily increased gas use until 1972. During the last decade natural gas use declined in all sectors, with the greatest decline occurring in the industrial sector.

In terms of natural gas shares over the 30-year period, the industrial sector had the largest drop, declining from 55 percent of the total to about 38 percent of total natural gas consumption, while the commercial sector experienced the largest gain, increasing its share from 7 to about 15 percent. The electric utilities sector also increased its share significantly, increasing from 12 to 18 percent of the total, and the residential sector increased its share by 4 percentage points to 29 percent.

These fuel share trends are the result of both market and regulatory forces, as mentioned above. Many industrial customers found that in the mid-1970s their gas supplies were unreliable and there was the threat that gas prices would rise sharply, due to resource depletion, regulatory actions, or both. During emergency shortage conditions (e.g., severe cold), residential/commercial customers were given priority, and Federal legislation called for industrial customers to pay more for gas in order to encourage fuel switching to coal (i.e., "incremental pricing"). After 1979, industrial customers began switching back to gas from residual oil because oil prices increased, and gas supply conditions eased. This, however, did not show up as an increase in total gas consumption by industry because fuel conservation measures and slack demand for industrial products lowered total energy demand.

PETROLEUM PRODUCT MIX

Refineries convert crude oils into a variety of products. Although most of the products are fuels, crude oils can also be refined to produce petrochemicals—i.e., feedstocks for the manufacture of a wide variety of plastics, synthetic fibers, paints and coatings, adhesives, piping, and the like.

Each of these products offers different opportunities for material substitution and conservation in its end-use applications. By examining the current product mix and its applications (next section), and how these have changed over time, the nature of U.S. economic dependence on oil can be described.

Out of at least 15 distinct product categories, the Energy Information Administration reports a 30-year consumption time series for six (see fig. 12 and table 3). The "other products" category includes kerosene, petrochemical feedstocks, lubricants, wax, petroleum coke, asphalt, road oil, still gas, natural gasoline, unfractionated stream, plant condensate, and miscellaneous other products. This category is a mixture of fuels and materials.

Before describing trends in greater detail for each of these product categories, it is important to note that production for all six increased during the 1952-72 period. A growing economy that required greater numbers of engines, greater quantities of heat and steam, and larger volumes of petroleum-based chemicals and synthetic materials was the primary force in driving oil use up.

Table 3.—EIA Petroleum Product Categories

	Percent of total liquids[a] used in 1982
1. Motor gasoline	41.5
2. Distillate fuel oil	18.8
3. Residual fuel oil	13.0
4. Ethane and liquified gases	6.5
5. Jet fuel	6.8
6. Other products	13.4
Total	100.0

[a] Includes natural gas liquids and all products made from crude oil.

SOURCE: Energy Information Administration, *1983 Annual Review of Energy*, Washington, DC, April 1983.

However, consumption of all products slipped in 1974 and 1975 as a result of rapidly rising fuel prices. After the initial price shock wore off and as real prices declined, the economy began to grow again in the mid-1970s and product demand rose until 1979. In the last 4 years, all but one product category—ethane and liquefied gases—declined as a result of price escalation, the economic recession, and the higher fuel efficiency of new cars. Each of the six major product categories is discussed below.

Motor Gasoline

Gasoline is used almost exclusively in automobiles and light trucks. Since 1952, the share of gasoline in total oil use has stayed in the neighborhood of 40 percent. When real oil prices were steady, growth in gasoline demand was relatively low, and when prices rose sharply in the last decade, consumption declined at a relatively slow pace. Since total oil consumption peaked in 1978, gasoline use has declined by a smaller percentage than four of the five other product categories. Perhaps a much sharper decline is imminent, as expected technological change would suggest (see ch. V). Because gasoline represents such a large portion of all petroleum products, however, even a small percentage decline translates into larger volume declines.

Distillate Fuel Oil

Distillate (#1 or #2) is used primarily for heat and mechanical motion (diesel). While #2 fuel oil and diesel are chemically distinct, they are generally considered as one fuel product because they come from the same boiling fraction in a barrel of crude oil and refineries can trade them off with little change in operations. Like gasoline, distillate has maintained over 30 years its share in total oil use, but its roughly 18-percent share is less than half that of the predominant product.

Residual Fuel Oil

The next largest single petroleum product category (measured by volume) is residual fuel oil (resid). As its name implies, it is the residuum, or bottom, of a barrel of crude, which remains after all other fractions have vaporized into the distillation column. Residual oil is generally too viscous to flow without preheating and special pumping. Therefore, its use is limited to large boilers. Residual fuel has been the only product category to lose its share of total petroleum use continually over the 30-year period, going from 21 percent in 1952 to 11 percent in 1982. Its most rapid share loss has occurred during the past 4 years, primarily because of the large decline in use by electric utilities. In general, this declining share has been the result of its relatively low end-use value, the availability of good fuel substitutes (e.g., coal and natural gas), and the increasing ability of refiners to crack large resid molecules into higher valued fractions, such as gasoline and distillate.

Ethane and Liquefied Gases

These relatively light hydrocarbons are used primarily as petrochemical feedstocks and secondarily for high-quality process and space heating, particularly in remote areas. Over the past 30 years, this category sharply increased its share in total oil use (from 4 to 10 percent) because both demand and supply conditions were favorable.

On the supply side, unlike other refined petroleum products, liquefied gases have an alternative source of supply in natural gas reserves. Since gas use expanded more rapidly than oil over this period, the potential supply of liquefied gases expanded at more than twice the rate of other petroleum products.

On the demand side, these light liquids are used primarily for chemical feedstocks, and demand for feedstocks has continued to be strong even during periods of sharply rising prices. The strength of this demand may be explained by the relatively rapid growth of the chemicals industry[6] and by the relatively low-cost share of feedstock materials in total petrochemical product cost leading to relatively low price elasticity for petrochemicals.

Jet Fuel

Jet fuel is the other product category that has sharply increased its share among all oil products over the last 30 years. However, this increase occurred entirely before 1973. Since then, its share has remained relatively steady. This category (slightly less than 7 percent of total product) is the least important of the five major products, as measured by volume consumed.

Other Petroleum Products

A diverse group of products are included in this category, making it difficult to generalize about end-use trends except to note that about 90 percent of the end uses are used in the industrial sector. The nonindustrial uses are primarily for kerosene for space heating and hot water and lubricants for transportation. Since the share of industrial activity in the economy has been steadily declining (see later section in this chapter), the share of this petroleum product group may tend to decline, as well. However, since 1952 this composite category has maintained its share in total oil consumption at around 13 percent. Although its share declined to about 12 percent in 1982, this appears to be the result of a temporary decline in industrial output associated with the deep recession in that year. The reasons for this share stability are the same as those for liquefied gases, given above.

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[6] Measures of relative growth for the chemicals industry are rendered imprecise by relative price changes over such a long time period (30 years). However, two growth rate comparisons are available which nevertheless clearly show the strength of this industry. First, as reported by the Department of Commerce (*The National Income and Product Accounts of the United States, 1929-76, Statistical Tables*, pp. 229-233), income generated (current dollars) by "chemical and allied products" grew at an annual rate of 7 percent, while the economy grew at 6.7 percent. Of course, the relative difference would be much greater if inflation were removed. Second, from 1969-80, the growth in the Federal Reserve Board Index for the chemicals industry was 3.9 percent, while that for all manufacturers grew at 3.25 percent. (See *Industrial Production*, Annual, Board of Governors of the Federal Reserve System.)

THE COMBINATION OF OIL PRODUCT MIX AND FOUR DEMAND SECTORS

U.S. oil use can be further examined by integrating oil product mix and end-use sectors. Table 4 shows major petroleum products categories supplied to each end-use sector for 1982.

Residential and Commercial Sectors

Residential and small commercial building owners typically use distillate or liquefied petroleum gas for space and water heating because these fuels are very convenient to use in equipment of moderate cost. On the other hand, residual oil is used only in the largest boilers in very large apartment and commercial buildings. This fuel is less expensive, but handling is more difficult and costly. Since 1977, #2 distillate fuel oil use has declined greatly, and use of #6 residual fuel oil and liquefied gases has declined by an even greater percentage (see fig. 12). A sharply rising trend in electricity use by these two sectors indicates that a substantial amount of oil is being saved by the substitution of electricity, which now exceeds oil as a heating source. Natural gas is used also as an oil substitute in these sectors. However, its increased use as an oil substitute is being offset by the use of more energy-efficient technologies and equipment and other conservation measures.

Electric Utilities

Ninety-three percent of the petroleum used by utilities in 1982 was residual fuel burned in boilers. Over the past 30 years, utilities have sharply reduced oil use, primarily by substituting coal and nuclear power. Most recently, large reductions in the use of #6 residual fuel have occurred because actual demand for electricity has fallen far below estimates. When faced with excess capacity, utilities will shut down oil boilers first to maximize savings in fuel costs. If demand suddenly increases, however, oil use will climb to the extent that coal and nuclear generating capacity are not available.

Transportation

Gasoline, diesel, and jet fuel are the primary products used by the transportation sector. Gasoline accounts for the largest share—65 percent; diesel—15 percent; and jet fuel—11 percent. Two of the three most important fuels, gasoline and jet fuel, are used almost exclusively in the transportation sector. Furthermore, the amount of distillate burned as diesel fuel in transportation is about equal to all other uses of distillate combined, and much of the distillate used in indus-

Table 4.—Refined Petroleum Products Supplied to End-Use Sectors, by Type, 1982 (thousand B/D)

Fuel	Residential/ commercial	Industrial	Transportation	Electric utilities	Total[a]
Motor gasoline	50	70	6,420	0	6,540
Distillate fuel oil (#2)	700	620	1,310	40	2,670
—Hot water and steam					
—Engine					
—Other					
Residual fuel oil (#6)	170	460	440	640	1,720
—Hot water and steam					
—Marine fuel					
LPG	260	1,210	20	0	1,500
—Heat and hot water					
—Industrial feedstock					
Jet fuel	0	0	1,010	0	1,010
Other[b]	60	1,700	100	10	1,860

[a] Sum of the parts may not equal the total because of rounding.

[b] Includes (in order of importance) asphalt, other petroleum feedstocks, still gas, petroleum coke, lubricants, kerosene, special naphthas, aviation gasoline, wax, and road oil.

SOURCE: Energy Information Administration, *1983 Annual Review of Energy*, Washington, DC, April 1983, p. 69.

try is also diesel fuel for engines, such as in agricultural, mining, and construction equipment. In addition to these fuels, smaller amounts of residual fuel oil are used in marine ships.

Industrial

The mix of petroleum products used in the industrial sector is by far the most varied. The only major petroleum products not used in this sector are the two aviation fuels (jet fuel and aviation gasoline). The industrial sector is the major consumer of asphalt, lubricants, road oil, and the other products included in the "other" category.

Compared to the other three sectors, the industrial sector employs the most diverse, complex, and rapidly changing technologies, and these make it difficult to predict future consumption patterns. However, industrial users have options to adjust to higher oil prices that are not available or at least not as effective for the other demand sectors. These include shifting away from products that use more oil to products that use less, changing production processes in order to switch fuels or to use oil more efficiently, and substituting skilled labor and control technology in order to maximize fuel efficiency. In lieu of an extensive description of fuel use technology in specific industries, behavior of this second most important oil-consuming sector is described first in terms of time trends in energy intensity and second in terms of historical analysis, which suggests the effect of petroleum price inflation on product mix.

INDUSTRIAL SECTOR ENERGY INTENSITY

Only two out of the four energy-consuming sectors—the industrial and utility sectors—measure the value of their activities or output by market prices. In the residential/commercial and transportation sectors, the value of goods and services produced can be estimated on the basis of the value of purchased inputs, but this provides only a lower boundary for value of output. Presumably, residential customers and automobile/truck drivers purchase petroleum because the heat and transportation derived from the fuel are worth more than its cost. However, since these are sales to final users, there is no market price to measure the value of actual end-use services.

For electric utilities, there is a market test of value. Since only a single commodity is produced, electricity, the value of production is simply the price per kilowatthour multiplied by the number of kilowatthours of electricity generated. Thus, in this case, energy intensity is proportional to engineering efficiency. Engineering efficiency rose significantly from about 21 percent (Btu electricity out per Btu fuel input) in 1952 to 29.5 percent in the mid-1960s and has leveled out since then.[7] Consequently, the energy intensity (value of output in constant prices divided by Btu inputs) declined by almost 30 percent by the mid-1960s, but has held steady since.

Industrial output can be measured in at least two different ways: 1) as an index of physical output, or 2) as an economic product. Both types of measurements involve difficult data analysis because of the diversity of industrial activities. Each of these output measures are discussed separately below because they give different perspectives on industrial energy intensity.

The Federal Reserve Board (FRB) has developed an index of industrial output designed to approximate the physical quantity of goods produced in mining and manufacturing. It does not include agriculture or construction. For this index, the FRB collects constant dollar or related physical unit measures of output or economic activity by 4- to 6-digit SIC[8] industries. In order to aggregate this large number of separate output indices into a single national index, the FRB normally uses fractional weights representing the share of each industry in total U.S. industrial value added. In other words, if plastic milk bottle makers contribute 10 times as much to real national product as contact lense makers, then the multiplicative weight applied to the output index number for milk bottles would be 10 times as large as the corresponding weight for contact lenses. Note that value-added weights eliminate double-counting of the plastic that goes into both products. That value is attributed to plastic manufacturers.

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[7] Energy Information Administration, *1982 Annual Review of Energy*, Washington, DC, April 1983, p. 13.

[8] The Standard Industrial Classification (SIC) defines industries in accordance with the composition and structure of the economy and covers the entire field of economic activities.

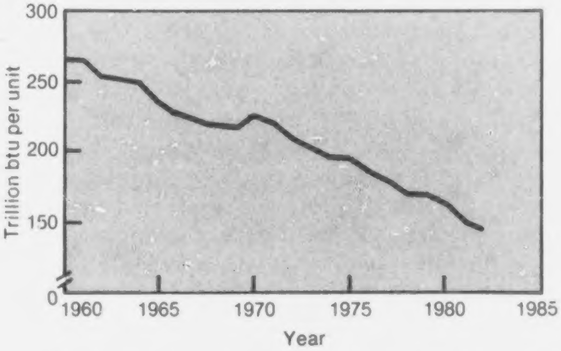
Dividing the FRB index of industrial output into energy used by mining and manufacturing yields the first indicator of industrial energy intensity. As shown in figure 14, all pertinent measures of energy per unit of output have fallen steadily, with the exception of a brief reversal around 1970. Based on these data, it is reasonable to conclude that technological advances over the last 20 years have permitted steady, substantial reductions in the amount of energy needed to produce industrial commodities.

A somewhat different view results if another reputable time series of industrial output is used. Industrial sector economic product is also measured as "value added" by, or "gross product originating" (GPO) from industry.[9] In 1952 total industrial GPO equaled about 38 percent of gross domestic product (GDP), but has since declined steadily, to about 31 percent in 1982. This measurement, in dollars, is obtained via two alternative methods. From the perspective of income generated from production, value added should equal payments to all workers and investors engaged in mining, manufacturing, construction, and agriculture, plus taxes paid by firms that are also so engaged. In terms of product sales, the same value should also be obtained by subtracting the sales value of all intermediate products (as defined above) from total industrial sales.

In fact, because of data limitations, both approaches are used to estimate industrial economic product, whether it is called value added or "gross product originating," and to cross-check data sources. Differences that arise between the two approaches must be reconciled by experienced judgment. The last step in the data analysis involves elimination of general price inflation by dividing the industrial product time series by a price deflator, which is based on a representative sample of industrial products. It is important to notice that upward or downward trends in the relative price of industrial products and changes in the product mix can make this time series behave differently than the index of physical output.

Industrial energy intensity as measured by the ratio of gross energy inputs to gross product originating is shown in figure 15. Prior to 1972, industrial energy use and dollar output grew apace; therefore, the intensity ratio stayed roughly constant at about 75,000 Btu/dollar. The probable reasons for this constancy, compared to the steady decline of the ratio of energy used to physical output (see above), are decreasing relative product prices and changing product mix. After 1972, energy use declined at an annual average rate of about 1.4 percent, while output continued to expand on the average of a little more than 1 percent per year. In other words, industrial

Figure 14.—Industrial Energy Intensity Using the FRB Output Index



SOURCES: Energy Information Administration, *State Energy Report, 1960 Through 1981*, DOE/EIA-0214(81), Washington, DC, June 1983; *Monthly Energy Review*, DOE/EIA-0035(83/07); Council of Economic Advisors, "Report to the President," app. A. in *The 1983 Economic Report of the President*, Washington, DC, February 1983.

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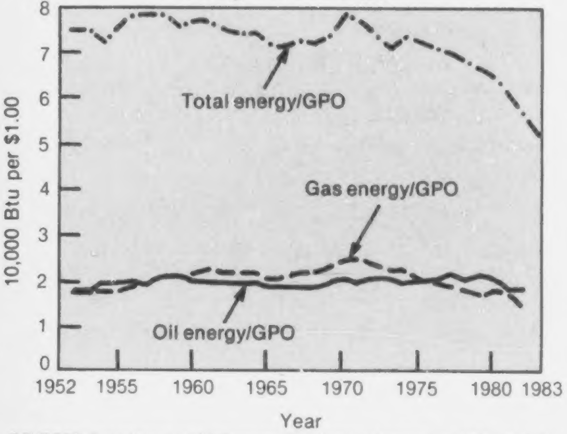
[9] There is a range of reputable time series estimates for industrial output since estimation involves many theoretical choices about what should be measured and problems related to how data are actually gathered. Discussions with data-base specialists indicate that, in general, the FRB index tends to show more rapid output growth than indices based on the quinquennial *Census of Manufactures*. The latter includes the estimates for industrial output, which are published as part of the National Income and Product Accounts (NIPA).

Figure 15.—Industrial Energy Intensity Using Census Data



SOURCES: Department of Commerce, *The National Income and Product Accounts of the U.S., 1929-76*, Statistical Tables; and the *Survey of Current Business;* and Energy Information Administration, *1982 Annual Review of Energy*, Washington, DC, April, 1983.

energy intensity made a sharp break from its past trend as it declined sharply over the last decade.

Compared to all sources of energy, the use of oil has moved more in step with industrial activity over the last 30 years, so industrial oil intensity has been relatively stable. This conclusion includes the last decade, when oil prices rose sharply. While total energy intensity declined by about 24 percent, oil intensity declined by only about 14 percent. Movements in natural gas intensity, on the other hand, were relatively large. While the other two intensity indicators exhibited minor fluctuations from 1952-1972, gas intensity grew by about 28 percent; and while overall energy intensity declined by about 14 percent during the last decade, gas intensity declined by about 35 percent.

INDUSTRIAL PRODUCT MIX SHIFT

When oil or gas prices increase, the costs and prices of goods and services, which use significant amounts of these fuels as inputs, also rise. This cost increase for final products can be moderated by investments in fuel efficiency improvements but cannot be entirely eliminated without technological innovation. Fortunately, higher fuel prices motivate innovations. Another important reaction to these rising prices is a shift in the overall mix of goods and services. In some product markets, rising prices induce sharp reductions in purchases, and so demand is said to be price *elastic*. However, in other markets, higher prices cause little change in sales volume, and so demand is called price *inelastic*.

For example, the demand for plastic milk containers is price elastic for two reasons: 1) the cost of plastic is a significant fraction of the total price of the milk to the consumer, and 2) paper containers are highly competitive both in cost and performance. Consequently, if the price of oil drives up the cost of plastic to bottlers, those bottlers will probably switch to paper. Over time, the shares of plastic and paper milk containers follow their relative prices.

In contrast, the demand for plastic in the manufacture of contact lenses is price inelastic. For this product, the price of plastic is not a major fraction of total cost and so an oil shock does not significantly raise the price of contact lenses. Furthermore, there is no good substitute material for making contacts and the other major alternative technology, eyeglasses, are also made primarily from plastic, so those with imperfect vision can do little else but pay the price.

After the two major oil price increases of the 1970s, large product mix shifts across the entire economy began to occur, and these shifts will take years to complete. Attempts to describe empirically the shifts that have accompanied these past oil disruptions are circumscribed by poor data and difficulties in isolating the impacts of an oil disruption from the effects of other disturbances and trends. Nevertheless, a useful snapshot of product mix shift following the 1973-74 disruption is provided in table 5. These data are based on industrial data collected by the FRB (see previous section) and on a number of related national indices, as described below.

Marlay has constructed a number of additional national indices using other weighting schemes based on fuel use for the same set of SIC industries.[10] Each industry was given a weight equal to its share in total industrial use of oil to construct an oil-weighted national index of industrial output. Similarly, a natural gas-weighted index was constructed, and so on for other fuels and combinations of fuels.

These alternative indices of industrial output are then compared in terms of their growth rates over time. If indeed there has been a shift away from oil-intensive commodities since 1974, then the oil-weighted time series should suffer a more dramatic decline after that year than the FRB series with value-added weights.

Table 5 reports Marlay's findings for the aggregate of manufacturing and mining. As shown, the value-added index lowered its average growth rate by 1.1 points (comparing the 19 years before 1973 to the 7 years after), while the oil-weighted index dropped by 1.8 points and the index weighted by the sum of oil and gas dropped by 2.1 points. Somewhat ironically, the coal-weighted index dropped the most (2.6 points), but that was due in large part to the steady decline of the integrated steel industry, which resulted from international and domestic economic events far removed from oil markets.

Marlay's analysis confirms that, indeed, industrial sector product mix of manufacturing plants and mines shifted toward less energy-intensive goods, including less oil-intensive goods. Although the shift away from oil was slightly smaller than the average for all fuels, the shift away from both premium fuels (oil and natural gas) was slightly greater than the average. The latter shift is relevant because of the large fuel-switching capability between oil and gas for stationary heat and steam applications. And as mentioned above, the relatively large decline in the coal-weighted index was only marginally related to the rising price of oil.

Table 5.—Growth Rates for Alternative Indices of Mining and Manufacturing Output

Index	Average growth rates 1954-73	1973-80	Difference
Coal weighted	1.9	−0.7	−2.6
Gas weighted	4.2	1.9	−2.3
Oil weighted	5.2	3.4	−1.8
Oil and gas	4.5	2.4	−2.1
Electricity	4.2	2.1	−2.1
Total energy	4.0	2.0	−2.0
Value added	4.0	2.9	−1.1

SOURCE: Robert C. Marlay, *Industrial Energy Productivity*, Ph.D. dissertation, Massachusetts Institute of Technology, May 1983, ch. 7.

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[10] Robert C. Marlay, *Industrial Energy Productivity*, Ph. D. dissertation, Massachusetts Institute of Technology, May 1983.

ECONOMIC RECESSION AND PRODUCTIVITY DECLINE

A final economic adjustment to an oil supply shortfall involves a decline in the overall level of economic activity. While this adjustment is difficult to isolate from other factors affecting economic activity, two basic cause-and-effect mechanisms are clearly operating.

Immediately following an oil disruption, there is a temporary readjustment process analogous to a business cycle recession. Within a short time after a sharp oil price increase, producers realize that their factor input mix is suboptimal because they are spending too much on oil, given their available options to increase profits by changing their technology or at least by reorganizing the production process. Similarly, consumers realize that they are spending too much on oil, given their lifestyle objectives and the cost and availability of oil substitutes. For both, the period immediately after oil prices have risen involves retrenchment because producer revenues and consumer purchasing power decline. Both reductions in economic activity can interact to amplify the resulting decline in GNP, at least in the short term.

Although it is extremely difficult to isolate just how much an oil supply shortfall may have contributed to a subsequent economic recession, it is worth noting that both the 1973-74 and the

1978-79 disruptions were immediately followed by economic recessions that apparently were caused to a large extent by these incidents (see fig. 16). While a general recession of economic activity is a negative impact, it also has the effect of lowering demand for oil and thus oil prices.

Although this short-term adjustment process is an important stabilizing force in oil markets, the primary subject of this assessment involves longer term adjustments, which depend primarily on technological options for oil replacement and on the willingness of investors to invest in these options. Investors respond to general economic conditions as well as to opportunities created by changing prices and technology. Immediately after the last two shortfalls, investment activity declined more than in proportion to GNP (see fig. 17), but the economy can be expected to come out of its post-shortfall recession, with investors leading the way, if oil replacement options are attractive.

Needless to say, it is exceedingly difficult to evaluate these replacement opportunities, even after the last decade of experience because so many other factors besides oil markets have contributed to the performance of the economy over that period. However, in the 5-year horizon of this assessment, the net macroeconomic impact of a permanent loss of oil supplies or permanent increase in the price of oil is most likely to be negative.

Figure 16.—Gross National Product Over Time (constant 1972 dollars)

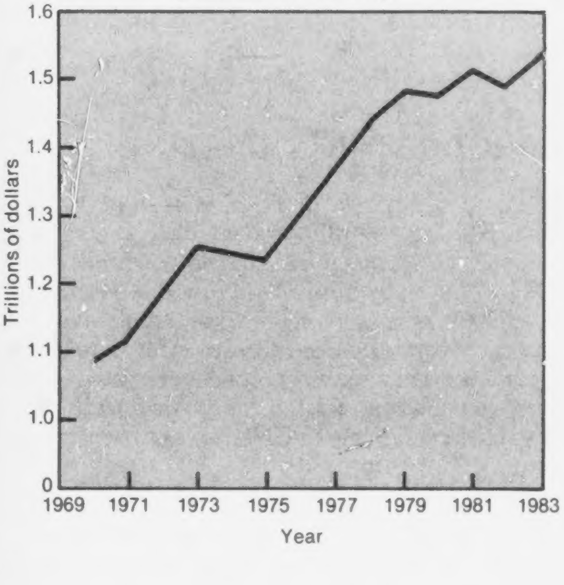
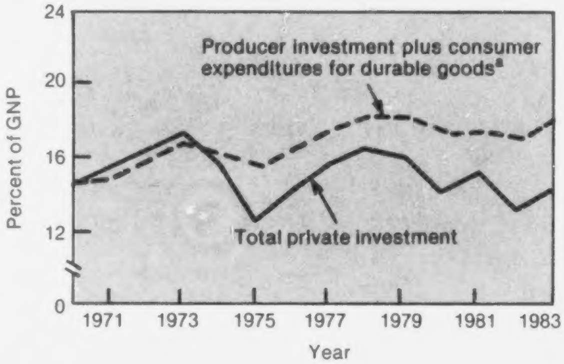


Figure 17.—Total Investment and Expenditures for Durable Goods[a] (as percent of GNP)



[a] Producer investment in durables is one component of total private investment. Consumer expenditures for durables is not included in total private investment but it is closely related because durables are investment goods. Both producer and consumer durables are also germaine to the discussion of investment for oil replacement.

SOURCES: *The National Income and Product Accounts of the United States, 1929-76*, Statistical Tables; and *Survey of Current Business*, "National Income and Product Accounts," Table 1.1, July 1983 and March 1984.

Barring technological breakthroughs or major changes in production processes or lifestyle, GNP and average labor productivity must decline because a permanent oil supply shortfall raises the cost of producing the prevailing mix of goods and services. Conversely, a permanent shortfall reduces the availability of a key resource input to the economy, and thus, everything else being more or less the same, total output must decline. Limiting attention only to changes in oil inputs becomes less realistic as the years pass following the onset of a shortfall. Indeed, based on the last two shortfalls, one might expect developments in technology and lifestyle to overcome shortfall losses within the time horizon of a decade, or at least to change expectations about the future which existed when imported oil was cheap and plentiful.

The point of this discussion is that oil consumption can be reduced by reducing economic activity, and that the market economy may decide that this is a better option than technical replacement. The main objective of the following discussion is to evaluate the technological options for reducing oil dependence and maintaining growth in the event of a future shortfall. The historical analysis provides an appropriate introduction to the technical analysis by showing that the economy has demonstrated resilience after the last two oil supply shortfalls, both in terms of continued economic growth and reduced oil intensity, presumably because oil replacement options have been effective.

Chapter IV

Fuel Switching

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Chapter IV
Fuel Switching

INTRODUCTION

Fuel use patterns in the United States have changed several times in the past 150 years. During the late 1800s, coal overtook wood as the principal fuel; and in this century oil and then natural gas use surpassed coal consumption.

In more recent years, however, the trend towards more oil and gas use has been reversed, at least temporarily. Between 1978 and 1982, oil use in the electric utility sector, as a percent of their total energy consumption, dropped from 17 percent in 1978 to 7 percent in 1982, while gas use remained relatively constant. Because electricity sales remained nearly constant, the drop in oil use was accompanied by an increase in coal consumption and, to a lesser extent, increased generation from hydroelectric facilities. (Nuclear power output remained nearly constant during the period.[1])

At the same time, residential and commercial consumption of oil, as a percent of total energy use (including wood[2]), dropped from 15 percent in 1978 to 9 percent in 1982, while natural gas's share of total consumption remained relatively constant. The drop in oil use was accompanied by an increase in electricity and, to a lesser extent, wood consumption.

Fuel use patterns in the industrial and transportation sectors, on the other hand, remained relatively constant during this period. In the industrial sector, oil and gas use, as a percent of total energy consumption, dropped by about 1 percentage point each between 1978 and 1982. The transportation sector remained primarily dependent on petroleum (except for natural gas used to pump gas through pipelines), although the use of natural gas and ethanol in cars and trucks increased slightly.

In all, petroleum consumption dropped from 47 percent of the total U.S. energy consumption in 1978 to 41 percent in 1982. Natural gas' share remained constant at 25 percent and coal's share increased from 17 to 21 percent in this period. The remainder was made up primarily of small increases in the shares of hydroelectric and nuclear generation and wood. These changes in the mix of fuels used, defined as "fuel switching," together with increased efficiency and reduced demand for energy services lowered U.S. demand for petroleum from 18.8 million barrels per day (MMB/D) in 1978 to 15.3 MMB/D in 1982, or about 19 percent.

In the event of a large oil shortfall, continued and accelerated fuel switching away from oil will be an important means of restoring the energy services formerly supplied by oil. Fuel switching often involves installation of new equipment, may require expansion of alternative fuel delivery systems, and always involves increased supplies of the alternative fuel.

In this chapter OTA considers several types of fuel switching in order to estimate their potential for replacing the petroleum lost in an oil shortfall. The next two sections summarize the fuel switching options examined and describe some of the technologies involved. Fuel supply constraints, including the potential for enhanced oil recovery, are then analyzed, followed by estimates of the rates that various technologies can be deployed. The chapter concludes with a brief summary of environmental impacts.

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[1] "Monthly Energy Review," Energy Information Administration, DOE/EIA-0035(83/10), October 1983.

[2] "Estimates of Wood Energy Consumption From 1949 to 1981," Energy Information Administration, DOE/EIA-0341, August 1982.

OPTIONS CONSIDERED

The oil replacement potential through fuel switching was assessed in a two-stage process. First a comprehensive list of major near-term fuel switching options (table 6) was screened to identify those options with the greatest potential for replacing large quantities of oil in a relatively short period of time. The options surviving the screening process were then examined in detail to estimate more precisely the quantities of oil that each could replace and the rate at which the technologies could be deployed.

For the purposes of this study, the options that were eliminated from further consideration were those that seemed least likely to be able to replace more than about 0.2 MMB/D of petroleum within 5 years after the onset of an oil shortfall beginning in 1985. Although most of the options listed in table 6 could replace significant quantities of oil if sufficient resources were devoted to deploying them, and some of the options eliminated could be important in specific localities, the screening process identified options most likely to be used extensively throughout the country. Some of the options eliminated and the specific reasons for eliminating them are given in appendix A to this chapter.

Table 6.—Oil Replacement Technologies Selected for Screening Evaluation

Energy supply/ technology-description	Remarks/examples
Natural gas in buildings, industries and electric utilities	Switch over from distillate/ residual fuel oil to natural gas
Electricity in buildings	Use of heat pumps, resistance heaters and space heaters
Coal and/or wood in buildings	—
Coal and solid wastes in industries and electric utilities	Direct firing of coal
Coal-liquid mixtures	Coal-oil, coal-water mixtures
Coal gasification	Low- and medium-Btu gasification
Coal liquefaction	—
Oil shale, tar sands	—
Solar energy	Use in buildings, industries and electric utilities
Wood in industries and electric utilities	Direct-firing both sectors; gasification in industries
Biomass liquid fuels in transportation	Use of ethanol from corn
Natural gas and LPG in transportation	—
Electricity in transportation	—
Mobile coal and wood gasifiers for transportation	—
Enhanced oil recovery	—
Increased natural gas production storage and delivery	—

SOURCE: Office of Technology Assessment.

The remaining fuel switching technologies, grouped into the aggregated categories which have been considered in more detail, are listed in table 7. The major options involve converting stationary uses of oil to electricity, natural gas, coal, and solid biomass. These fuels can also be used as replacements for liquid fuels in the transportation sector, but the constraints are considerably more severe than for stationary oil uses.[3] Ethanol from grain is also included for more detailed consideration, because it is a well-established technology that produces a high-grade liquid fuel, the leadtime for constructing distilleries is normally less than 3 years, and the distillery does not need to depend directly on oil or natural gas as a fuel.

Table 7.—Categories of Oil Replacement Technologies Evaluated in Detail

Sector	Technologies
Electric utilities	Conversions to solid fuels and natural gas Completion of new generating facilities currently under construction
Residential and commercial space heat and hot water	Conversion to natural gas, electricity, and solid fuels
Industry	Conversion of boilers to solid fuels and natural gas
Transportation	Conversion to compressed natural gas, liquefied petroleum gas, and solid fuels (with mobile gasifiers) Increased ethanol production
All	Enhanced oil recovery

SOURCE: Office of Technology Assessment.

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[3] Electric vehicles were also eliminated from detailed consideration because of the severity of these constraints.

TECHNOLOGIES

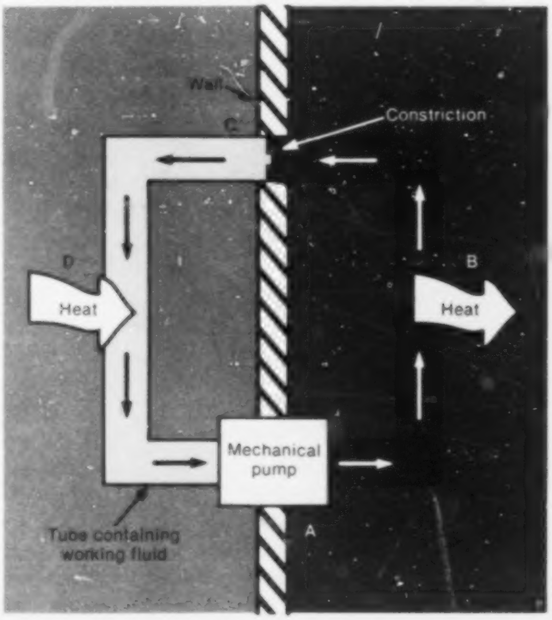
Several of the fuel switching technologies, such as conversion to natural gas, are widely understood and will not be considered in this section. Others, however, require some explanation; and they are described below in order to provide an understanding of some of the factors that affect potential oil replacement through fuel switching.

Electric Heat Pumps

Heat pumps are devices for space heating[4] that are based on the fact that the temperature of many gases increases when they are compressed, and their temperature drops when they are decompressed. The heat pump works by circulating a gas through a tube that runs partly inside and partly outside of the building that is being heated (see fig. 18). The gas is compressed in the part of the tube that is inside the building so that it is hotter than the inside air and releases heat to that air. The gas is decompressed in the part of the tube outside the building so that it is colder than and absorbs heat from the outside air. The net result is that heat has been transferred or "pumped" from the outside air to the inside air. (Obviously, by running the pump in reverse—compressing the gas in the tube outside of the building and decompressing it in the inside part of the tube—heat can be pumped out of the building, and the device becomes an air-conditioner.)

As long as the difference between the inside and outside air temperatures is not too great, a heat pump can pump more energy in the form of heat into a building than is consumed in the form of electricity to run the device. Its efficiency, or heat delivered to the inside air divided by the energy consumed to run the device, can then be greater than 100 percent. However, when the outside temperature drops, the efficiency also drops; and below certain outside temperatures, usually around 20° to 30° F, it is more efficient to use electric resistance heating (which has an efficiency of 90 to 100 percent). Consequently, heat pumps are usually equipped with electric resistance heaters, which are used when the outside temperature is low. Nevertheless, practical heat pumps, which are not designed to double as air-conditioners in the summer, can usually achieve an overall efficiency of about 200 percent. Designing heat pumps for both heating and cooling involves some design tradeoffs, which reduce overall heating efficiency to about 150 percent.

Figure 18.—Principle of an Electric Heat Pump



The function of most heat pumps is based on the fact that the temperature of most fluids rises when the fluid is compressed and falls when the pressure on the fluid is reduced.[a]

In the above diagram the fluid in the tube is compressed by a mechanical pump (A) as it enters the building. This raises the fluid's temperature to a level that is above the inside air temperature, causing heat to flow from the working fluid into the air inside the building (B). The fluid then passes through the constriction (C) as it leaves the building, causing the pressure on the fluid to drop. The apparatus is designed so that the pressure drop is sufficient to cool the fluid to a temperature which is below the outside air temperature, causing heat to flow from the outside air into the working fluid (D). The process is then repeated.

[a] A common example of this occurs in bicycle pumps. When air is compressed in the pump to fill a bicycle tire, the air's temperature rises causing the pump to become hot.

SOURCE: Office of Technology Assessement.

By way of comparison, oil heating has an efficiency of about 65 percent. Consequently, an efficient heat pump requires about one-third as much energy (in the form of electricity) as an oil furnace requires (in the form of oil) to deliver the same amount of heat. As long as the electricity is generated from nonpremium fuels (i.e., coal, nuclear, or hydroelectric), the heat pump is an attractive alternative for replacing premium fuels. If, however, the electricity is generated with natural gas or oil, for which the efficiency of converting fuel to electricity is about 32 percent, this potential gain in premium fuel replacement is lost, since it would require at least as much oil or gas to produce the electricity as would be replaced by the heat pump. Consequently, in terms of oil replacement, heat pumps are attractive only where marginal electricity is generated from fuels other than oil.[5]

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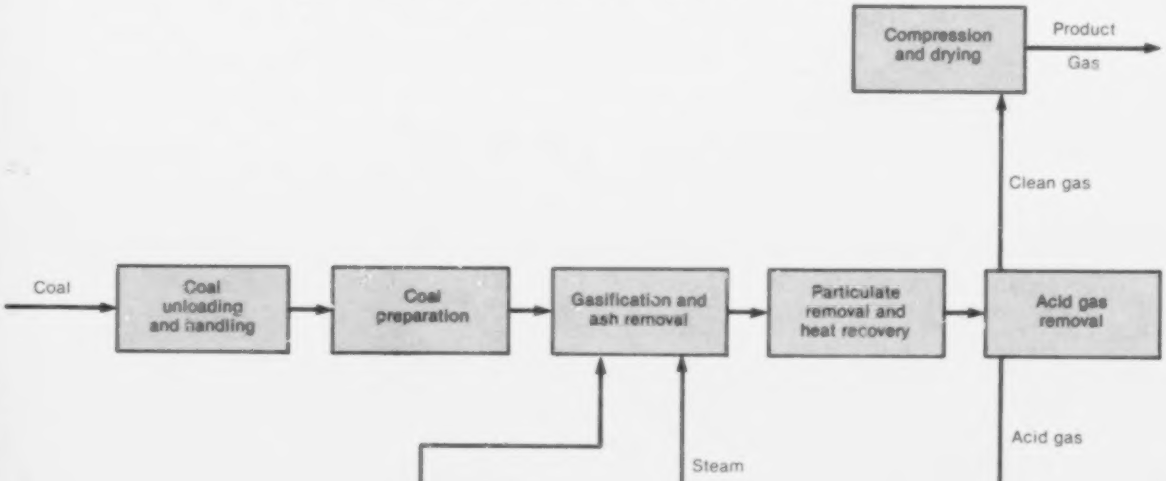
[4] Heat pumps can also be used for hot water heating, but only space heating is described here.

Conversion to Solid Fuels

There are three basic technologies considered for converting oil-burning boilers to use solid fuels (principally coal and wood). First, the boilers can be modified to burn the solid fuel directly. Second, the fuel can be gasified in an onsite, air-blown gasifier (see fig. 19). The gasifier partially burns the fuel to produce a low-energy fuel gas which is then burned in the boiler. Third, the boiler can be converted to burn coal-water mixtures (CWMs) (see fig. 20). These are mixtures containing up to 70 percent pulverized coal in water. Both direct combustion and gasification are commercial technologies, although further development probably could significantly im-

Figure 19.—Coal Gasification Plant—Block Flow Diagram



SOURCE: Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase I—The Technologies," contractor report to OTA, April 1983.

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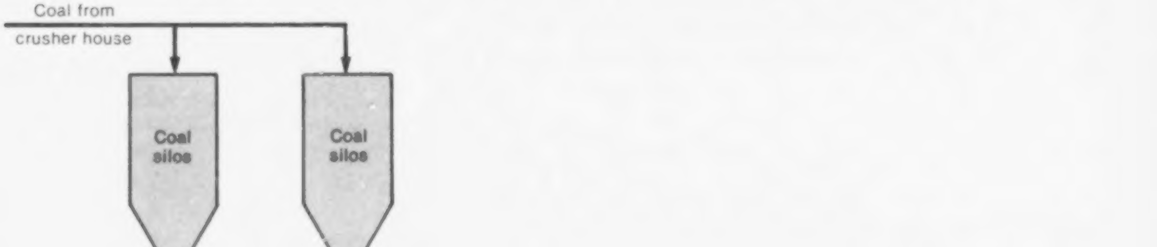
[5] If the oil used for electric generation is residual fuel oil, the situation is somewhat more complicated. Upgrading residual oil to middle distillates and gasoline is only about 70 percent efficient (Purvin & Gertz, Inc., "An Analysis of Potential for Upgrading Domestic Refining Capacity," prepared for the American Gas Association, 1980). Consequently, in principle, some increase in the supplies of refined liquid fuels could be achieved by burning residual oil for electricity and using the electricity for heat pumps to replace home heating oil, as compared to simply upgrading the residual oil and using fuel oil for space heating. In practice, however, the region where oil use for electric generation is most likely to continue after an oil shortfall is in the Northeast, where the cold winters reduce the efficiency of the heat pumps. Consequently, burning oil to produce electricity for heat pumps would probably lead to a net increase in oil consumption in this region; and it would be, at best, a questionable strategy to promote heat pumps as a means of displacing oil there.

Figure 20.—Schematic Flow Diagram of a Coal-Water Mixture Preparation Plant


Coal from
crusher house
Coal silos
Coal silos
Feeder
Feeder
Additives
Water
Rod mill
Ball mill
CWM storage tank
CWM mix tank
Transfer pump
Recirculating pump
Burner pump
To burners

SOURCE: Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase I—The Technologies," contractor report to OTA, April 1983.

prove the gasifiers. CWM technologies are currently being tested, and they are likely to be commercial by 1985.

All three technologies require the installation of ash recovery and disposal systems and particulate control systems (to reduce particulate emissions) at the boiler site. Direct combustion and air gasification also require solid fuel storage and handling facilities at or near the boiler site. CWMs, however, can be prepared at off-site CWM plants. Because the CWM is a liquid, much of the oil storage and metering system can be used for the CWM after various valves and pumps have been replaced. This is a principal advantage of CWMs over the other technologies because it reduces the space requirements for conversion to the use solid fuel.

Converting boilers to solid fuels often leads to a derating of the boiler—i.e., the boiler's maximum steam output per unit time is reduced. This results from various combinations of: 1) the need to reduce the speed with which the combustion gases pass through the heat exchanger in order to reduce the abrasive effects of the ash contained in these gases, 2) lower flame temperatures, and 3) larger combustion gas volumes (as compared to oil or natural gas). Depending on the boiler design, the derating can range from negligible amounts to over 50 percent of the output before the conversion. Where the derating is large, conversion to solid fuels would be less attractive and the end users may require the installation of additional solid fuel boilers in order to make up the lost steam output.

In the utility sector, there are three basic types of boilers, and each type requires somewhat different modifications. First are the boilers that were originally designed for coal but were subsequently converted to oil. (These are usually the easiest to reconvert to coal and generally experience the smallest derating.) The oil-designed boilers are of two types, called type 1 and type 2. The type 1 boilers are similar to coal-designed boilers in terms of hearth configuration,[6] heat exchanger tube spacing, and other important factors; and these boilers can also be converted to solid fuels. However, type 2 boilers (about 35 percent of the oil-designed boiler population[7]) require such extensive modifications that generally it is not practical to convert them. Consequently, for the purposes of this study, OTA has assumed that only the coal-designed and type 1 oil-designed utility boilers would be converted to solid fuels.

The population of industrial boilers has not been surveyed in the same detail as utility boilers. Consequently, OTA has simply assumed that 50 percent of the large (greater than 50 million Btu per hour (MMBtu/hr)) industrial boilers currently burning oil are suitable for conversion to solid fuels. Although there will be exceptions,[8] OTA also assumed that most of the small (less than 50 MMBtu/hr) industrial boilers would not be converted to solid fuels because of space limitations and the inconvenience and extra labor associated with solid fuel combustion.

Ethanol

Ethanol is a high-octane liquid fuel that can be used to fuel engines designed or modified for its use, or it can be blended with gasoline and the blends can be used in unmodified gasoline engines. Currently, the major use of fuel ethanol (about 500 million gallons per year) is as an octane-boosting additive to gasoline. These blends, which consist of 10 percent ethanol and 90 percent unleaded gasoline, were originally called "gasohol" but now are usually referred to as "premium unleaded gasoline with ethanol."

Ethanol is currently produced from ethylene (a byproduct of oil refining) and from biomass. U.S. production of petrochemical ethanol was about 200 million gallons in 1981,[9] almost all of which was used for chemical and pharmaceutical purposes. Although 1981 ethylene production (29 billion pounds[10]) would have been sufficient for 7 billion gallons of ethanol, using it to produce fuel ethanol would have diverted it from its higher value chemical uses. Consequently, this option has not been considered for fuel production.

Ethanol from biomass, the main source of fuel ethanol, is produced by fermenting a sugar solution and then distilling the solution to concentrate and purify the ethanol (see fig. 21). The sugar solution can be obtained from sugar crops, the starch in grains, or cellulose (contained in wood, plant herbage, the paper and wood in municipal waste, etc.). However, cellulose-derived sugar is relatively expensive because the processes either give low yields of sugar or consume large quantities of expensive chemicals and require expensive equipment.[11] The economics also generally favor the use of grain, principally corn, over sugar crops as the source of sugar in the United States, although there are site-specific exceptions to this.

A byproduct of producing ethanol from grain is a substance called "distillers' dry grain" (DDG), which contains most of the protein originally contained in the grain. The DDG can be used as a substitute for soybean meal and other protein concentrates in animal feeds. Above about 2 billion gallons per year of ethanol production, how-

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[6] Particularly the size of the hearth, which determines the length of time that the fuel remains in the combustion zone for a given air and fuel flow rate. Coal and wood react more slowly than does oil, so they require a longer residence time in this zone.

[7] "Survey of Oil-Fired Utility Boilers—Potential for Coal-Oil Mixture Conversion," prepared by MITRE Corp. for U.S. Department of Energy, DOE/FE/53179-01 UC-90E, July 1980.

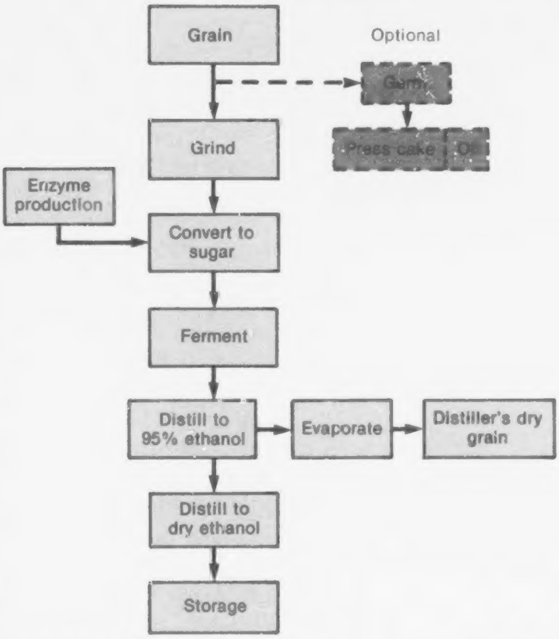
[8] R. Hodam, R. Williams, and M. Lesser, "Engineering and Economic Characteristics of Commercial Wood Gasifiers in North America," Hodam Associates, Inc., SERI/TR-231-1459, November 1982.

[9] *Chemical & Engineering News,* June 14, 1982.

[10] Ibid.

[11] *Energy From Biological Processes, Volume II—Technical and Environmental Analyses* (Washington, DC: U.S. Congress, Office of Technology Assessment, OTA-E-128, September 1980).

Figure 21.—Process Diagram for the Production of Fuel Ethanol From Grain



SOURCE: Office of Technology Assessment.

ever, the U.S. animal feed markets would begin to saturate; and this would have an adverse effect on the economics of ethanol production and increase the agricultural impacts of supplying the grain. (See "Fuel and Grain Supplies" below.)

Another concern is whether ethanol can replace more oil than is consumed in producing it—i.e., its net oil replacement. This involves three major areas: 1) distillery fuel use, 2) energy credits for ethanol's octane-boosting properties, and 3) grain production.

New, large-scale ethanol distilleries are generally fueled with coal, and their oil consumption is negligible. Experience to date, however, indicates that small, onfarm distilleries are usually fueled with oil;[12] and this is likely to result in distillery oil consumption that is at least half the energy content of the ethanol produced.[13] Consequently, unless onfarm ethanol production is negligible or small-scale distillers begin to use solid fuels, distillery oil consumption could reduce the net quantity of oil replaced by ethanol significantly. For the purposes of this study, however, OTA assumes that most of the ethanol will be produced in large, coal-fired distilleries.

The second factor in ethanol's oil replacement potential involves its octane-boosting properties. Under more or less normal circumstances, addition of ethanol to gasoline enables the refiner to produce a lower octane gasoline and thereby reduce the refinery energy use. This energy "credit" typically amounts to 5 to 50 percent of the energy content of the ethanol.[14] As discussed in appendix B of this chapter, however, changes in the product mix and processing needs at refineries following a large oil shortfall could reduce significantly or eliminate this energy credit. Consequently, OTA does not include a refinery energy credit when calculating ethanol's net oil replacement under conditions of a large shortfall.

The third factor is the fuel used to produce the grain, which is discussed in detail under "Fuel and Grain Supplies" below. When this agricultural energy use is included, the combined results indicate that ethanol production can, at best, lead to a net oil replacement equal to about half the energy content of the ethanol. And if the increased demand for grain leads to unfavorable (from an energy point of view) shifts in agricultural production and/or the distilleries are fueled with oil or natural gas, ethanol production will probably not reduce oil consumption and it could even lead to an increased demand for oil.

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[12] "Fuel Alcohol on the Farm—A Primer on Production and Use," U.S. National Alcohol Fuels Commission, Washington, DC, 1980.

[13] Fuel consumption reported by the small-scale distillers is less than this, but the numbers reported probably do not include mash preparation, distillery sterilization, and DDG drying. OTA's estimate of the energy consumption is based on the best available technology for all the processes involved in ethanol fermentation and distillation; and inefficiencies in small-scale operations would probably increase their energy consumption above our estimate.

[14] *Energy From Biological Processes, Volume II,* op. cit.

Compressed Natural Gas in Motor Vehicles

Compressed natural gas (CNG) can power existing automobiles and trucks if the fuel system is appropriately modified. Because natural gas is a high octane fuel, however, it is best suited for spark ignition (basically gasoline) engines. Currently, there are approximately 20,000 to 30,000 CNG-powered vehicles in the United States and 300,000 to 400,000 worldwide.[15] [16] In addition, there are at least six suppliers of CNG conversions kits in the United States.[17]

Conversion of a vehicle to CNG is relatively simple and can be accomplished in less than 8 hours. It consists of installing cylinders to hold natural gas pressurized at 2,500 pounds per square inch (psi) together with the requisite fuel lines, valves, pressure regulators, and carburetor modifications to deliver the gas to the engine and to refuel (see fig. 22). Most vehicles are converted for dual fuel use so that they can run on either gasoline or CNG. Vehicles typically have a range of about 100 to 200 miles on CNG between refills.

Some other aspects of CNG vehicles are as follows:

- **Refilling.** The time needed for refills varies from 2 to 5 minutes on a fast-fill device (which requires a bank of high-pressure storage cylinders) to 4 to 14 hours on a slow-fill device (in which the vehicle is connected more or less directly to a compressor). A typical refill station might contain one fast-fill device together with several of the slower filling ones.[18]
- **Market.** Until there are a large number of CNG vehicles on the road, the most likely markets for CNG conversions are vehicles in captive fleets, where all of the fleet vehicles are refilled at a central location. This would maximize the use of the refill equipment and thereby lower the per-unit costs.
- **Engine power.** Because the engine in a dual-fuel vehicle is not optimized for CNG use, it develops 10 to 20 percent less power with CNG than with gasoline. When maximum power is required, however, the engine can be switched back to gasoline.
- **Safety.** Although there is always the potential for fires that are difficult to control and explosions if CNG fuel systems rupture, CNG vehicles have an impressive safety record to date. Of the estimated 1,360 collisions involving CNG vehicles in the United States, including 183 rear-end collisions, none caused a failure of or fire involving the CNG fuel system.[19] The safety record in Italy is also excellent. Nevertheless, this safety record could be reversed if designed safety margins were reduced in order to cut costs or lower the weight of CNG systems.

Liquefied Petroleum Gas in Motor Vehicles

Liquefied petroleum gas (LPG) is a mixture of light hydrocarbons extracted from raw natural gas at natural gas processing plants or produced as a byproduct of oil refining. Although the hydrocarbons are gases at atmospheric pressure and room temperature, they liquefy when subjected to moderate pressures (e.g., 150 psi), and the resultant LPG has an energy density (energy per unit volume) that is 72 percent as great as gasoline.

Precise estimates of the number of LPG-fueled vehicles in the United States are not available. The National LP-Gas Association estimates 1.5 million vehicles;[20] but calculations based on Energy Information Administration data for LPG used as an internal combustion fuel put the number at considerably less than 1 million.[21] Never-

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[15] "Compressed Natural Gas (CNG) Vehicle System Information Paper," Gas Service Energy Corp., Kansas City, MO, 1982.

[16] "Assessment of Methane-Related Fuels for Automotive Fleet Vehicles," vol. 2, DOE/CE/50179-1, U.S. Department of Energy, February 1982; and "State of the Art Assessment of Methane-Fueled Vehicles," DOE/CE-0026, U.S. Department of Energy, February 1982.

[17] Ibid.

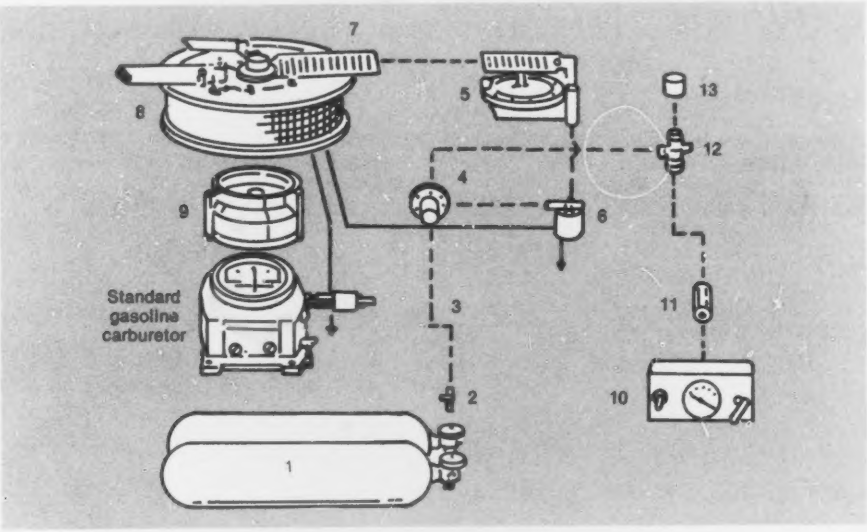
[18] Gibbs & Hill, Inc. "Oil Replacement Analysis Phase I—Selection of Technologies," contractor report to OTA, April 1983.

[19] Ibid.

[20] P. Ayler, National LP-Gas Association, Oak Brook, IL, private communication to Gibbs & Hill, Inc., Oct. 29, 1982 and Nov. 3, 1982.

[21] EIA ("Petroleum Supply Annual 1982," vol. I, U.S. Department of Energy, DOE/EIA-0340(82)/1, June 1983) reports that, in 1982, 644 million gallons of LPG were used as fuel in internal combustion engines. Assuming that the average vehicle (van, truck, and car) gets 15 miles per gallon (mpg) of LPG and travels an average of 10,000 miles per year, the number of LPG fueled vehicles would

Figure 22.—Components of CNG Vehicle Conversion



1. **CNG Storage Cylinders:** CNG is stored on board the converted vehicle at 2,400 psi in the U.S. Department of Transportation 3AA rated cyclinders.
2. **Manual Shut-Off Valve:** Each CNG storage cylinder is equipped with a high pressure ball valve which allows manual shut-off of CNG as an added safety feature.
3. **Fuel Supply Line:** The CNG supply line is made of high pressure steel tubing with a minimum working pressure rating of not less than 3,000 psi and a test pressure rating of 12,000 psi. It is ¼" thick and is manufactured to Society of Automotive Engineers specifications.
4. **First Stage Regulator:** The primary regulator reduces CNG from 2,400 psi storage pressure down to 60 psi. It is tested to withstand pressures in excess of 15,000 psi.
5. **Second Stage Regulator:** The secondary regulator reduces CNG from 60 psi down to less than one pound working pressure. This regulator design has been used by the gas utility industry for many years and is rated for inlet pressures up to 125 psi.
6. **CNG Solenoid Valve:** A 12 volt DC pilot-operated solenoid, located between the first and second stage regulators, controls the flow of CNG into the system.
7. **Vapor Hose:** The vapor hose supplies CNG from the second stage regulator to the gas/air mixer. It is impervious to CNG and capable of sustaining five times the maximum service pressure.
8. **Gas/Air Mixer:** This specially designed unit operates on the diaphragm controlled variable venturi principle. It meters CNG into the carburetor as required for combustion and maintains the proper fuel to air ratio at all levels of engine demand.
9. **Carburetor Adaptor:** This unit adapts the gas/air mixer to the standard carburetor in a straight-set or offset configuration.
10. **Fuel Selector Control Panel and Gauge:** The dash-mounted panel incorporates a sturdy push-pull cable with a handle for switching from one fuel to the other. A pressure gauge indicates the amount of CNG remaining in the vehicle.
11. **Gauge Isolator:** The isolator is installed in the high pressure fuel supply line behind the pressure gauge to prevent CNG from entering the passenger compartment.
12. **Combination Valve:** The combination check and fill valve allows CNG to flow through the fuel supply line to the storage cylinders and functions as a relief device to guard against overpressurization. It also automatically seals the system after refueling.
13. **Refueling Connection:** The refueling connection is designed to receive a probe-type refueling coupling and is equipped with an interlock switch to prevent the vehicle from being started inadvertently during refueling.

SOURCE: "The Dual Fuel BiPac System — Vehicle Conversion," Dual Fuel Systems Inc., Culver City, CA, 1981 theless, there have been reports that as many as 300,000 vehicles were converted to use LPG in 1981.[22] Furthermore, Ford Motor Co. began selling LPG-fueled cars in 1982, and they expect their 1982 sales of 1,500 vehicles to rise to 6,000 in 1983.[23]

Converting a gasoline-fueled vehicle to LPG entails installing an LPG fuel tank, fuel lines and filter, a device to vaporize the LPG and regulate the gas pressure, and a gas air mixer (see fig. 23). The conversion can be done in a few hours, and the converted vehicles generally can burn either gasoline or LPG. Furthermore, the National Fire Protection Association (NFPA) has developed standards governing the installation procedures and major LPG fuel system components, and the National LP-Gas Association has a program that certifies installers to the NFPA standards.

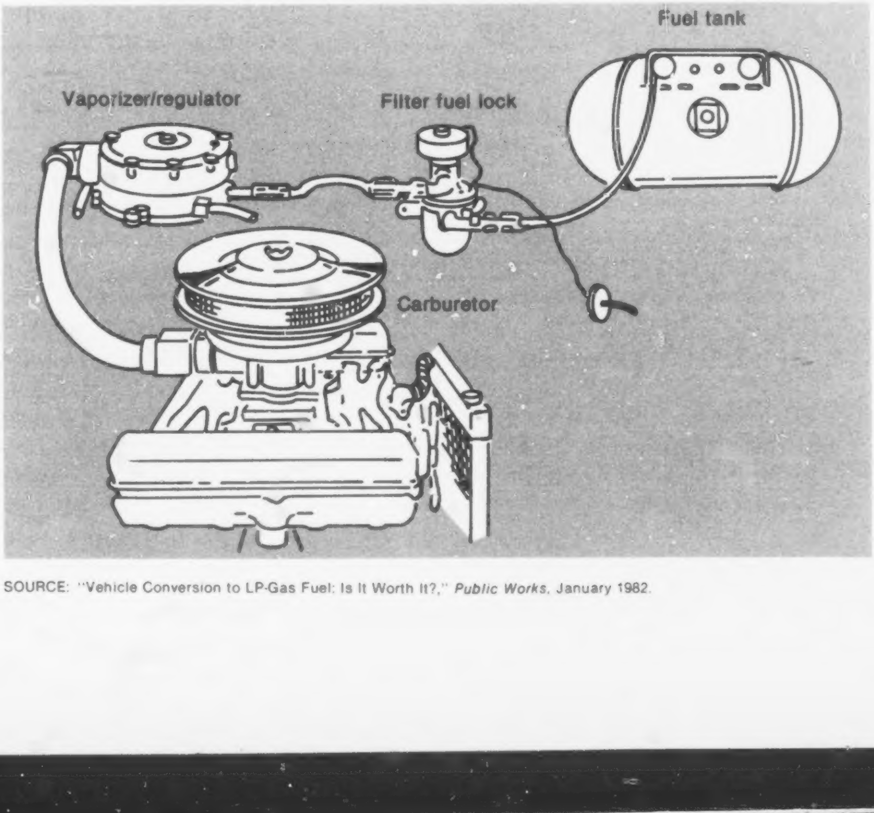
Refueling with LPG is somewhat more complex than with gasoline, because the filling station and vehicle tanks are pressurized. However, because LPG is liquid and the pressures involved are not great, refueling can be done quickly and presents no unusual difficulties.

Mobile Gasifiers

Gasifiers are devices that partially burn solid fuels to produce a low-energy fuel gas. For the purposes of this report, OTA defines mobile gasifiers as gasifiers attached to motor vehicles in which the fuel gas powers the vehicle. The gasifier can be mounted directly to the vehicle—e.g., on a bumper, inside the vehicle shell, in a truck's bed—or it may be mounted on a trailer drawn behind the vehicle.

During World War II, mobile gasifiers were used in several industrialized countries, including England, France, Italy, Germany, Sweden, and Japan. By 1943 there probably were several hun-

Figure 23.—Components of LPG Vehicle Conversion



SOURCE: "Vehicle Conversion to LP-Gas Fuel: Is It Worth It?," *Public Works*, January 1982.

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be about 966,000. However, some of this LPG is used for stationary engines, the 15 mpg average fuel efficiency is probably too high, and 10,000 miles per vehicle year may be too low. All of these potential errors would tend to exaggerate the number of LPG-fueled vehicles. In fact in its Annual Report to Congress, EIA lists LPG use in transportation at 0.01 quad/yr or 110 million gallons. This would put the number of transportation vehicles at perhaps 170,000; but other vehicles in construction, mining, and agriculture would increase the total.

[22] "Vehicle Conversions to LP-Gas Fuel: Is It Worth It?" *Public Works*, June 1982.

[23] "Ford Introduces a Gas Burner," *Machine Design*, Apr. 22, 1982; and R. J. Nichols, Ford Motor Co., communication to Gibbs & Hill, Inc., Mar. 17, 1983.

dred thousand (and perhaps as many as 1 million) vehicles fueled by gasifiers.[24] Nevertheless, additional development is required in order to optimize designs for modern vehicles and to establish design standards, but this does not present any serious problems. Consequently, while mobile gasifiers are not a commercial technology at present, there are no fundamental barriers that would prevent them from becoming commercial within a relatively short time.

A typical gasifier fuel system would consist of the gasifier, heat exchanger to cool the fuel gas,[25] a filter system to remove particulates from the gas, tubing to deliver the gas to the engine, and a device to mix the gas with appropriate quantities of air before it enters the engine (see fig. 24). In most cases, the gasifier system would be installed in a way that would allow the engine to run either on petroleum or on the fuel gas. In gasoline engines, the fuel gas would be ignited by the engine's spark plugs, and no gasoline would be necessary when the gasifier is operating. For diesel engines, however, small amounts of diesel fuel would have to be injected in order to ignite the fuel gas; and modifications to the diesel injection system might be necessary to limit the power output at full throttle so as to avoid excessive engine wear. The installation and any necessary modifications, however, could probably be completed in one day.

The size of the gasifier will depend on the power and driving range needed, but the gasifier for an average passenger car might be a cylinder that is about 1.5 ft in diameter and 4 ft long. Such a gasifier would provide a driving range of about 300 miles on coal or 75 miles on wood.[26] The heat exchanger and filter would be somewhat smaller than the gasifier and might typically be the size of the vehicle's radiator. Other designs are both possible and likely, however.

After the ash is removed and the gasifier is filled with fuel, the fuel is ignited with a small flare. Air then must be drawn through the gasifier for 2 to 5 minutes before the exhaust gas can be ignited, and full power does not develop until after about 20 minutes of operation. Even with full gasifier output, however, the power of the vehicle engine would be less than 60 to 70 percent of its power when operating on gasoline, or, in the case of a diesel engine, about 80 percent of the power (if diesel injection is minimized). In addition, the gasifier operates best when its power output is reasonably constant and it responds slowly (relative to gasoline engines) to changes in power requirements. Although petroleum fuel could be used when the engine is first started and when full power is needed, the limitations of gasifiers indicate that they are best suited to long trips with relatively stable power needs, such as in intercity driving.

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[24] Rasor Associates, Inc., "Evaluation of Mobile Gasifiers for the OTA Oil Replacement Analysis Project," contractor report to OTA, July 1983.

[25] The gas has to be cooled to increase its energy density and to prevent misfiring. Without gas cooling, engine performance would not be acceptable.

[26] Rasor Associates, Inc., op. cit.

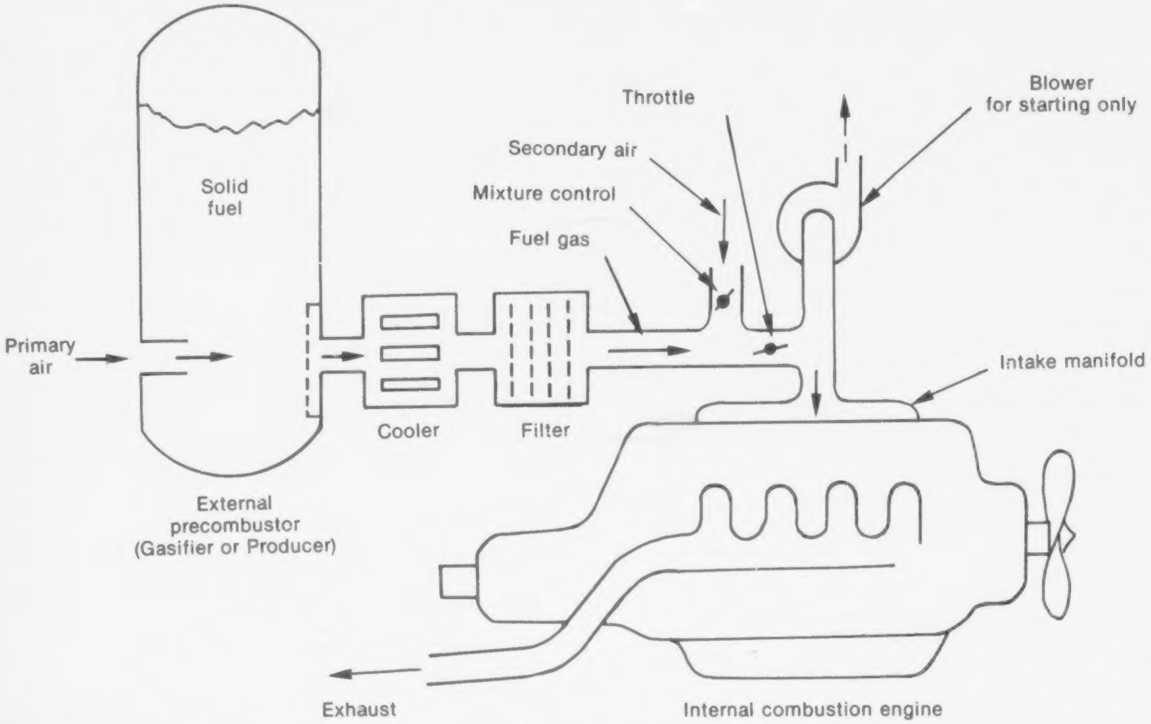
FUEL AND GRAIN SUPPLIES

Following the postulated oil shortfall, there will be an increase in conventional oil and gas exploration and development. Enhanced oil recovery projects started before the shortfall will begin to produce, and any surge production capacity will be utilized to maximize domestic oil production.

OTA has not assessed the potential quantities of oil from these sources, but has assumed that these activities will, at best, keep domestic oil production constant during a 5-year period following the onset of a shortfall. To the extent that actual production differs from this assumption, it would be roughly equivalent to a less or more severe oil shortfall.

Beyond this assumed baseline for domestic oil production, several other fuel sources have been identified for more detailed study as replacements for the petroleum lost in an oil shortfall. Domestic oil production can be increased (relative to

Figure 24.—Basic Elements of the Mobile Gasifier-Engine System



SOURCE: Rasor Associates, "Evaluation of Mobile Gasifiers for The OTA Replacement Analysis Project," Contractor report to OTA, February, 1983.

what it otherwise would have been) through new enhanced oil recovery (EOR) projects. Oil users can also switch to natural gas, coal, and solid biomass fuels. And grain can be used as a feedstock, together with coal or solid biomass as a fuel, for ethanol production.

The more detailed analysis of these options, however, indicates the following: Supplies of solid fuels are likely to be adequate. The supplies of natural gas are uncertain, but it is reasonable to assume that around 2 trillion cubic feet per year (TCF/yr) could be available for fuel switching. On the other hand, although EOR can produce significant quantities of additional oil in the time period of 5 to 10 years after the onset of an oil shortfall, its contribution within less than 5 years is doubtful, due to the long leadtimes before enhanced production actually materializes. And, although adequate quantities of grains could be supplied well before ethanol distilleries could be built, the resultant increased use of energy by agriculture would greatly reduce the net oil replacement from ethanol.

Potential supplies of each of these fuels and grain are discussed in more detail below. In addition, where it is an important factor, the interdependence of fuel supplies is also considered. Availability of electricity is not considered in this section, however, because it depends heavily on construction and fuel switching plans of electric utilities, and it more properly fits into the following section on fuel switching.

Coal

Based on the analysis presented in the section on fuel switching, full implementation of the fuel switching options, including the use of coal-water mixtures and direct coal firing in utility and industrial boilers, would increase coal consumption by up to 115 million tons/yr. Up to 20 million additional tons/yr could be used for new EOR projects. OTA assumed that to prevent an increase in sulfur emissions without the use of flue gas desulfurization, those who switch from oil to coal would use low-sulfur coal (less than 1 percent sulfur), which would account for 65 million tons/yr of the increase in coal use. The remaining increase would be in new coal-fired powerplants and for increased electricity production in existing powerplants, together with smaller amounts for space heating and hot water.

In 1978, U.S. coal production was 665 million tons,[27] of which 219 million tons contained less than 0.8 percent sulfur and 143 million tons contained 0.9 to 1.2 percent sulfur.[28] Consequently, over 40 percent of the total shipments contained less than 1 percent sulfur. Of this low-sulfur coal, about half was eastern coal.[29] By 1982 coal production had grown to 833 million tons, with 707 million tons consumed domestically and, although explicit data are not available, the proportion of low-sulfur coal and low-sulfur eastern coal was probably similar to the 1978 data. Furthermore, in 1974 the U.S. Demonstrated Reserves Base[30] of low-sulfur coal amounted to about 200 billion tons, of which 33 billion tons were estimated to exist in Appalachian and Midwestern coal fields. More recent studies[31] indicate that recoverable reserves (the most restricted category) of Appalachian low-sulfur coal amount to 14 billion tons. Consequently, although low-sulfur coal production would have to increase by about 25 to 30 percent to meet the maximum projected demand, coal supplies appear to be adequate; and, if necessary new mines could be opened well within the 5-year time period.

Wood and Other Solid Biomass

Potential supplies of wood and other solid biomass show large variations from region to region. Wood supplies are greatest in the South, Great Lakes region, and the Northeast, with lesser supplies in the Pacific and Rocky Mountain regions. The potential for energy from crop residues is concentrated in the agricultural regions of the Midwest, South, and Pacific coast regions. Potential supplies of forage grasses are mainly in the regions east of the Mississippi River.[32] Supplies of municipal solid waste are, of course, largest in the large metropolitan areas.

Wood is currently the largest source of energy from solid biomass in the United States. Potential future supplies of wood also appear to be considerably larger than those of crop residues, grasses, and municipal solid waste taken together; and the technologies for using wood are more widely disseminated and better understood than those for the other sources of solid biomass. Consequently, of these sources, wood appears to have the greatest potential for displacing petroleum during an oil shortfall in this decade.

If harvested as part of an integrated forest management program, the potential wood energy supplies in each region are more than adequate to supply the projected incremental demand for all solid fuels (including coal) as replacements for oil, although individual States may have to import from neighboring States. (See fig. 25 for the Standard Department of Energy regions used in this report and table 8 for wood energy potential by region.) The tightest supplies would be in the New York/New Jersey region, where the incremental demand for solid fuel could be about equal to the potential wood supply; but additional wood could be imported from regions 1 and 3, which have the potential for large surpluses. If the wood is harvested in a haphazard manner, however, supplies would be considerably smaller (following initial clearing of existing forests), wood energy markets could divert commercial timber (used for lumber and paper pulp) from the forest products markets, and environmental damage could be extensive.

In practice, market confusion surrounding a rapid growth in demand for wood would be likely to cause at least temporary shortages of wood in numerous locations. However, since wood (and

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[27] Of which 4 percent went to exports and 11 percent were for coke plants.

[28] "Sulfur Content in Coal Shipments 1978," DOE/EIA-0263(78), June 1981.

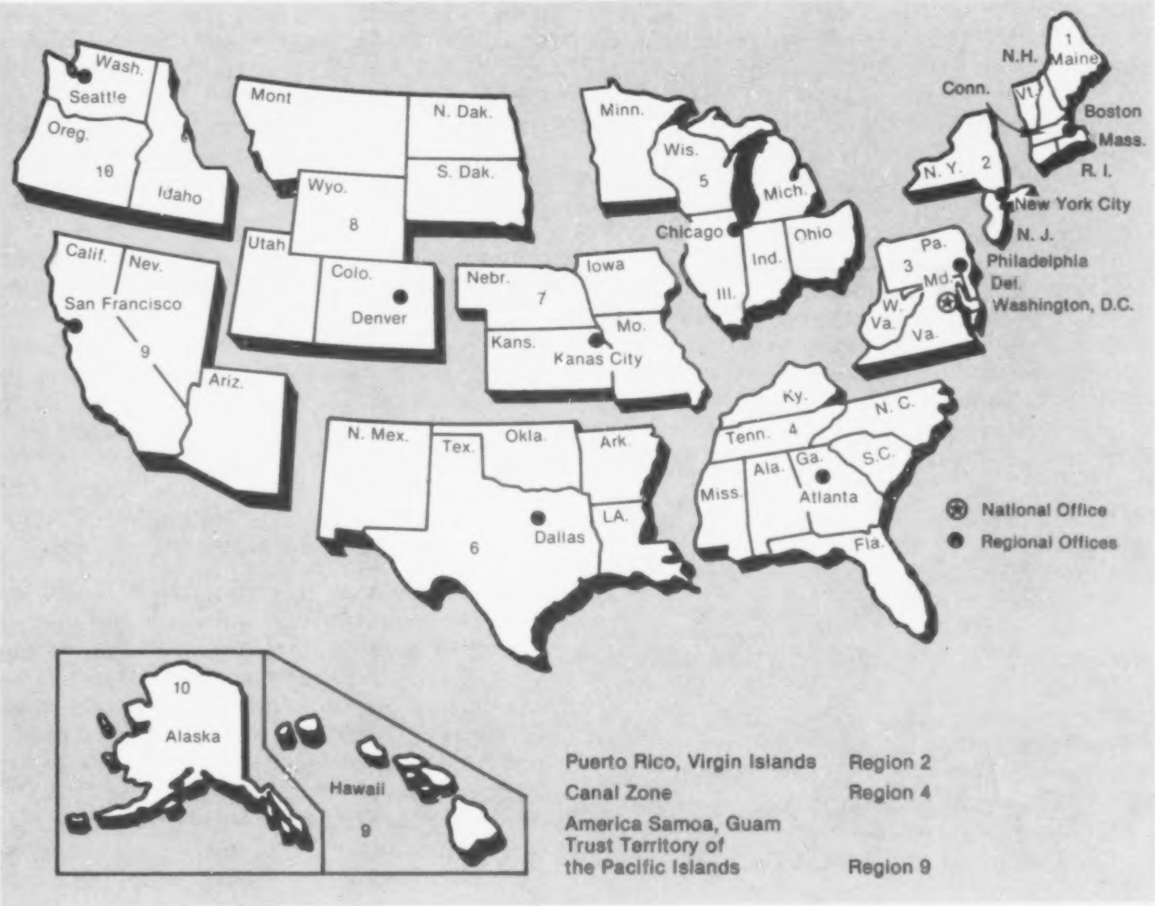
[29] Ibid.

[30] The Demonstrated Reserve Base represents the amount of coal contained in coal beds that meet certain criteria of geological assurance, depth, and seam thickness.

[31] R. L. Carmichael, "Report on Recoverable Reserves and 1978 Production of Low Sulfur Bituminous Coal Fields in the Eastern States," Oak Ridge National Laboratory for U.S. Department of Energy, January 1981.

[32] *Energy From Biological Processes* (Washington, DC: U.S. Congress, Office of Technology Assessment, OTA-E-124, July 1980).

Figure 25.—Federal Regions


Wash.
Seattle
Oreg.
10
Idaho
Mont
N. Dak.
S. Dak.
Wyo.
8
Utah
Colo.
Denver
Calif.
Nev.
San Francisco
9
Ariz.
Minn.
Wis.
5
Mich.
Chicago
Ind.
Ohio
Ill.
Nebr.
Iowa
7
Kans.
Mo.
Kanas City
N. Mex.
Tex.
Okla.
Ark.
LA.
Dallas
6
Ky.
Tenn.
4
N. C.
S.C.
Ala.
Ga.
Miss.
Atlanta
Fla.
1
N.H.
Maine
Vt.
Conn.
Boston
Mass.
R. I.
N. Y.
2
New York City
N. J.
Pa.
3
Md.
Philadelphia
Del.
W. Va.
Va.
Washington, D.C.
National Office
Regional Offices
10
Alaska
Hawaii
9
Puerto Rico, Virgin Islands — Region 2
Canal Zone — Region 4
America Samoa, Guam Trust Territory of the Pacific Islands — Region 9

SOURCE: U.S. Department of Energy.

Table 8.—Potential Wood Energy Production by Region, Assuming 10 Quadrillion Btu/Yr Increment

Region	Quantity (10^{15} Btu/yr)
1	0.68
2	0.36
3	1.0
4	2.8
5	0.88
6	1.2
7	0.22
8	0.57
9	0.52
10	1.76
Total	10.0

SOURCE: Office of Technology Assessment.

other solid biomass) would be competing with coal for the available markets, it is likely that wood use would be concentrated primarily in locations where the potential supplies are very much larger than the demand, such as in heavily wooded areas. Thus, it is highly unlikely that the availability of wood or other solid biomass would constrain the deployment of technologies for replacing oil with solid fuels.

Natural Gas

The American Gas Association recently estimated that the United States currently could produce about 2.7 TCF/yr more natural gas than the 18 TCF/yr consumed in 1982.[33] OTA's assessment of natural gas availability,[34] however, indicates that future supplies are extremely uncertain. Consequently, rather than attempting to derive a highly uncertain estimate, OTA has assumed that there will be a 2 TCF/yr of natural gas available to replace oil. (This amount of gas is equivalent in energy content to 1 MMB/D of oil.) To the extent that this gas is not available from domestic production (including unconventional sources) and various domestic conservation measures, OTA assumes that imports from Canada and Mexico can be increased to provide the supply. It should be noted, however, that feasible increases in efficiency of natural gas use in the industrial, residential, and commercial sectors, could replace about 2 TCF/yr of gas currently being used in those sectors (see ch. V). Consequently, if domestic production can be kept constant and the efficiency changes are implemented, this supply of gas would be available without increased imports.

Because natural gas availability is assumed to be limited, it is necessary to postulate how it will be allocated among the various consuming sectors. To do this OTA first assumed that the residential/commercial sectors would have priority over the other sectors for the use of natural gas. Based on this assumption, OTA found that about 0.9 TCF/yr could be used in the residential and commercial sectors for heat and hot water. The remaining 1.1 TCF was then distributed between the industrial and utility sectors in proportion to amount of oil they would be consuming after feasible conversions to coal had been completed. This resulted in an allocation of 0.9 TCF/yr to the industrial sector[35] and 0.2 TCF/yr to electric utilities.

Liquefied Petroleum Gas

Increased domestic production of natural gas would also lead to increased supplies of liquefied petroleum gas (LPG) from natural gas plant liquids (NGPL). In 1981, NGPL production was about 11 percent of natural gas production, on an energy basis.[36] Newly discovered supplies of natural gas generally contain less NGPL, however. Assuming that the new gas production is 9 percent NGPL, that 60 percent of the NGPL is LPG, and that 75 percent of the LPG is suitable for internal combustion engines, an increase of 2 TCF/yr in natural gas production would result in an additional 0.04 MMB/D oil equivalent of LPG suitable for engines. This would also result in 0.05 MMB/D oil equivalent of NGPL and LPG not suitable for engines, but which could be used for some stationary fuel purposes. To the extent that the natural gas is made available through increased efficiency of natural gas use, however, less incremental LPG would be available.

Enhanced Oil Recovery

The total amount of oil recovered from some oil fields can be increased through enhanced oil recovery (EOR). The process consists of injecting a fluid (generally carbon dioxide (CO_2) or steam) into an oil field through a series of injection holes. Approximately 2 years after injection begins, oil production from the field starts to increase.

Two areas of the United States that are major candidates for EOR are Texas and California. In Texas the fields would be injected with CO_2 that could come from natural CO_2 fields in Colorado and New Mexico and the recovery of CO_2 from the effluents of chemical plants (notably ammonia plants) and, possibly, electric powerplants. The leadtime for constructing the necessary equipment and pipelines and drilling the injection holes is about 2 years[37] (see fig. 26).

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[33] "Natural Gas Production Capability in 1983," American Gas Association, May 27, 1983.

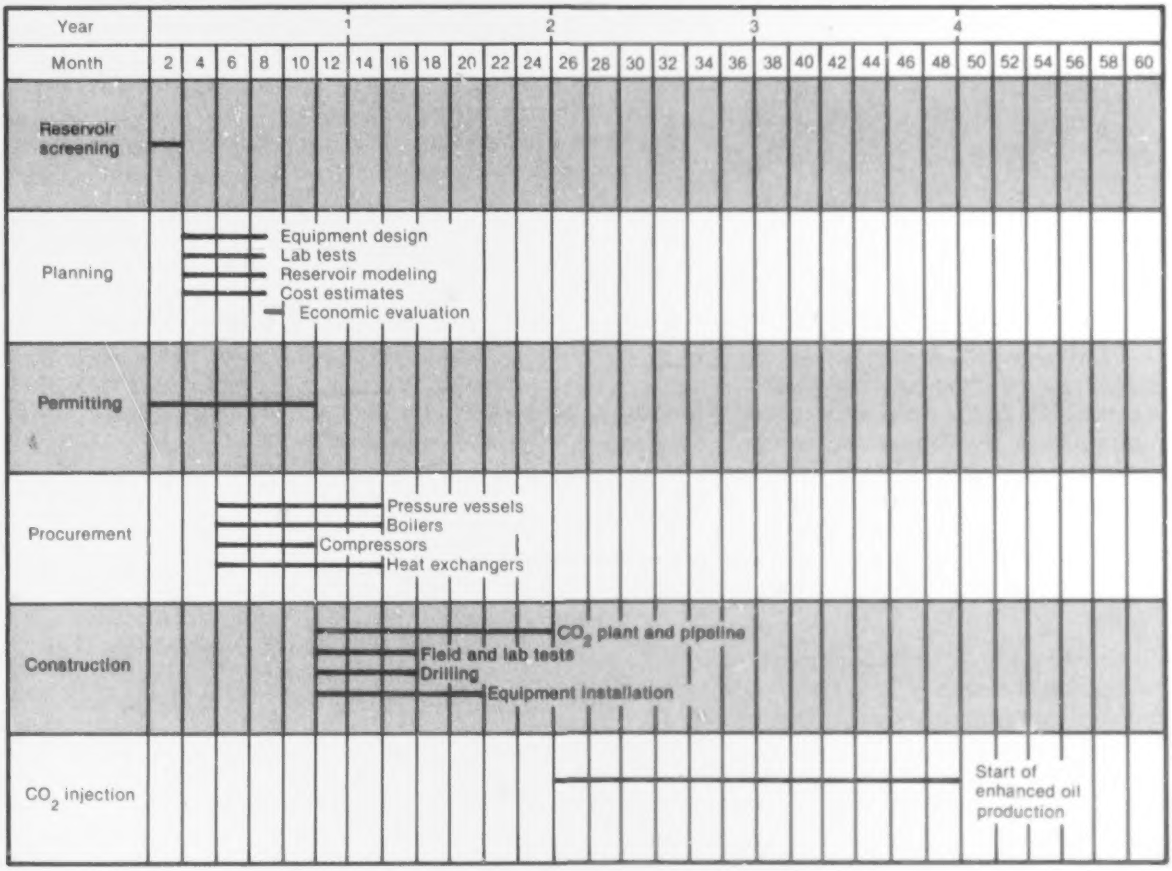
[34] *U.S. Natural Gas Availability: Conventional Gas Supply Through the Year 2000—A Technical Memorandum* (Washington, DC: U.S. Congress, Office of Technology Assessment, OTA-TM-E-12, September 1983).

[35] If 5 billion gal/yr of ethanol are produced (with an energy equivalent of 0.2 MMB/D), then natural gas use for fertilizer production would increase by about 0.05 MMB/D. Although this gas use would decrease the amount of gas available for other uses in the industrial sector, use of the ethanol would free up some additional oil that could be used in the industrial sector. By using a net energy approach (i.e., assuming that this ethanol would lead to a net reduction in oil consumption equal to 0.1 MMB/D), this increased agricultural use of gas as well as oil is accounted for; and no inconsistencies are introduced by adding the oil replaced by ethanol (0.1 MMB/D) to the industrial oil replaced by gas (0.9 TCF or 0.45 MMB/D).

[36] "Petroleum Supply Annual," op. cit.

[37] Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase II—Evaluation of Selected Technologies," contractor report to OTA, August 1983.

Figure 26.—Schedule for Accelerated EOR CO_2 Flooding Project



SOURCE: Office of Technology Assessment.

In California, steam would be injected. The leadtime for erecting the boilers and other equipment and drilling the injection wells would be about 1¾ years without flue gas desulfurization (scrubbers) and at least 2½ years with scrubbers[38] (see fig. 27).

With the time required for construction and the delay before enhanced recovery materializes, at least 4 years would be required before any additional oil could be produced through new EOR projects. Once enhanced production begins, however, it could increase rapidly to as much as 0.8 MMB/D within a year, as illustrated in figure 28. If oil rather than coal is used to produce the steam in the California EOR projects, as is now the practice, net oil production would be reduced by over 0.1 MMB/D.

Numerous complications could easily delay these projects by a year or more, however. In Texas there could be delays in securing cooperative agreements with electric utilities and chemical plants and in securing rights of way for the pipelines. In California virtually all of the production would occur in Kern County, where the current levels of sulfur dioxide (SO_2), carbon monoxide, particulates, and oxidants in the air all exceed the ambient air quality standards (AAQS).[39]

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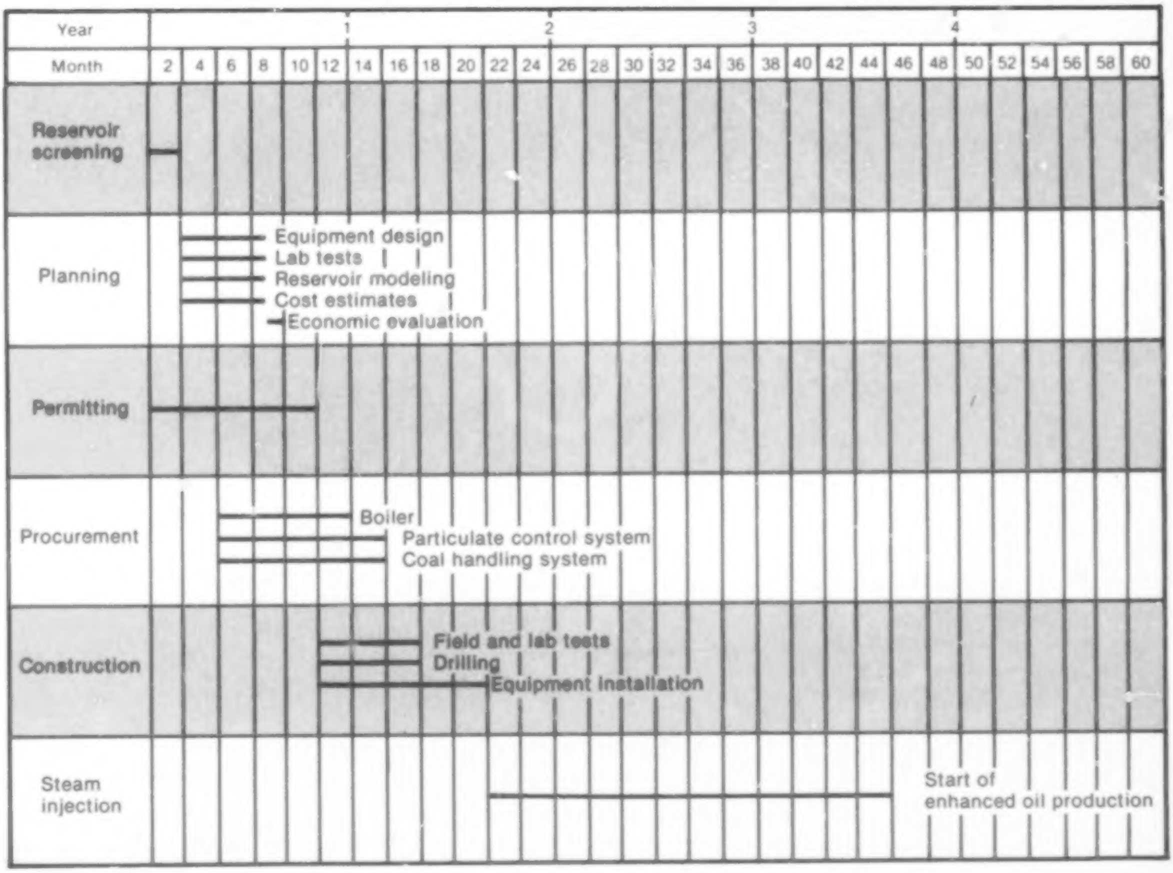
[38] Ibid.

[39] Frank T. Princiotta, Director, Industrial Environmental Research Laboratory, U.S. Environmental Protection Agency, Research Triangle Park, NC, private communication, July 8, 1983.

Figure 27.—Schedule for Accelerated EOR Steam Flooding Project



SOURCE: Office of Technology Assessment.

Furthermore, the ambient nitrogen oxide (NO_x) level is about 95 percent of the AAQS.[40] Consequently, permitting delays are likely, particularly if a large number of projects are started simultaneously. In addition, the EOR projects will have to compete with the industrial oil users that are switching to solid fuels for much of the equipment they will need and they will have to compete with conventional oil and gas exploration and development for drilling rigs.

Because of the long leadtime before enhanced oil production begins and because of the possibilities for delay, the potential for new EOR projects within 5 years after the beginning of an oil shortfall is highly uncertain. In OTA's judgment, these characteristics of EOR put it more nearly in the category of long leadtime technologies with high production potentials, such as synfuels, than in the area of short-term responses, which are being emphasized in this assessment. Therefore, potential oil production from new EOR projects is not included as one of the short-term responses in this assessment; although it, together with fossil synfuels, could provide large quantities of liquid fuels in the time period of 5 to 10 years or more following an oil shortfall.

Grain

OTA's analysis of ethanol production indicates that distilleries capable of producing up to almost 5 billion gal/yr of ethanol (about 0.2 MMB/D

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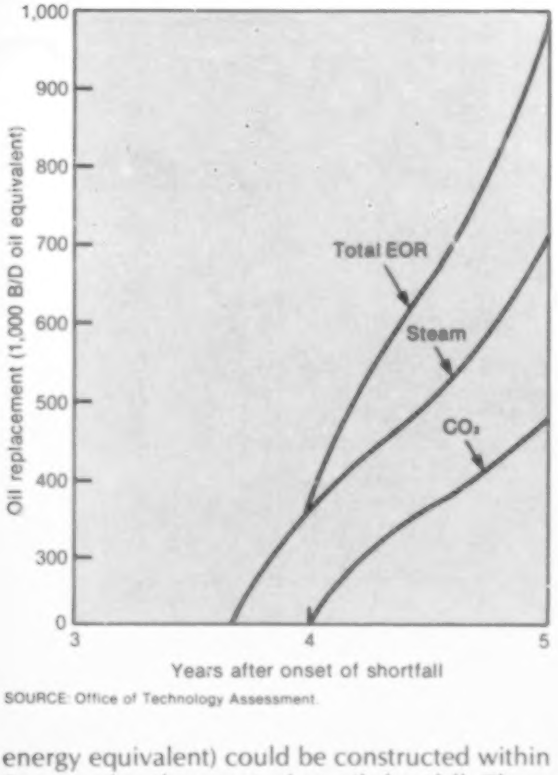
[40] Ibid.

Figure 28.—Potential Oil Production Rate for Enhanced Oil Recovery



SOURCE: Office of Technology Assessment.

Photo credit: U.S. Department of Energy

Fuel ethanol is produced from corn in this large distillery in central Illinois

energy equivalent) could be constructed within 5 years after the onset of an oil shortfall. These distilleries would require about 50 million tons of grain or 2 billion bushels of corn per year.

In 1981, U.S. grain production was about 333 million tons, of which 55 percent was for domestic use and 45 percent was exported. Corn production in that year was 8.2 billion bushels, up from an average of about 7 billion bushels per year during the previous few years. Therefore, supplying the feedstocks for 5 billion gal/yr of ethanol production would require about a 15-percent increase in grain production or a 30 percent increase in corn production.[41] With the appropriate price incentives and government policy (within the authority contained in existing legislation), agricultural production of conventional grains could almost certainly increase by these amounts well before the distilleries could be built.[42]

If the ethanol is derived from corn, a byproduct of the conversion process is distillers' dry grain (DDG), gluten, or some other such protein concentrate, which can be used to replace the soybean meal used as a protein supplement in animal feeds. Consequently, soybean production could be reduced somewhat; and, for 2 billion gal/yr of ethanol production, the net increase in cropland under cultivation would be considerably less than 5 million acres. Beyond about 2 billion gal/yr, however, the soybean meal markets would begin to saturate; and a total of at least

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[41] Assuming that average corn yields on the marginal land are 70 bushels per acre and that they are fertilized with 150 lb/acre of nitrogen, 35 lb/acre of phosphorus, and 100 lb/acre of potassium, then nitrogen, phosphorus, and potassium production would have to increase by about 20, 9, and 32 percent, respectively ("Agricultural Statistics 1981," U.S. Department of Agriculture, 1981). This can probably be accommodated within the 5-year timeframe, however.

[42] On the other hand, rapid increases in the production of crops that currently have low production volumes could be constrained by the availability of seed or other material (e.g., shoots, seeding tubors) needed to plant the crop.

20 million acres of new cultivation would be required to satisfy corn demand for the production of 5 billion gal/yr of ethanol.[43]

With this level of increase, one would expect significant shifts in the quantities of agricultural commodities produced in the various regions; and with it there could be subtle, though significant, changes in agricultural energy use. Furthermore, oil refinery operations and needs would change during the postulated oil shortfall, and this would affect the energy credits that could be ascribed to ethanol for its octane-boosting properties under more normal circumstances. These effects are discussed in more detail in appendix B to this chapter.

The net result is that after changes in agricultural energy use are accounted for, production of 5 billion gal/yr of ethanol (energy equivalent of 0.2 MMB/D of oil) could result in anywhere from a 0.15 MMB/D reduction to a 0.12 MMB/D **increase** in oil consumption. The former would occur if only minimal shifts in agricultural production from one region to another occur and there is a surplus of natural gas (used to produce farm fertilizers and pesticides). The latter would occur if there are modest, but unfavorable (from an energy point of view) shifts in agricultural production and there is no surplus of natural gas (so that use of this fuel in agriculture limits the switching from oil to gas in other sectors).

In OTA's opinion, it is unlikely that there would continue to be surpluses of natural gas several years after the onset of the oil shortfall. And increasing corn production by the quantities needed for 5 billion gal/yr of ethanol synthesis would almost certainly lead to some interregional shifts in agricultural production, such as in the example given in appendix B. Consequently, OTA considers it highly unlikely that production of 5 billion gal/yr of ethanol from corn could replace more than 0.1 MMB/D of oil; and it is possible that it would replace 0.05 MMB/D or less. (See box on Calculating Ethanol's Energy Balance.)

Use of significant quantities of other grains as feedstocks would differ from the use of corn in two respects. The oil and gas used to grow a given amount of grain could vary from 20 to 25 percent less than corn (e.g., wheat, oats, barley) to about 15 percent more than corn (e.g., grain sorghum). But in all cases, the yields per acre cultivated are significantly less than that for corn, and the amount of cropland under cultivation would have to increase proportionately more. Depending on how the agricultural system adjusted to this new demand, the net oil replacement (per gallon of ethanol) from other grains could range from about the same as to significantly less than that from corn.

Consequently, although the agricultural system could supply the grain needed for the maximum levels of ethanol production that are technically feasible within 5 years after an oil shortfall, the increased energy consumption in agriculture would greatly reduce the potential oil replacement.

DEPLOYMENT OF FUEL SWITCHING TECHNOLOGIES

The above analysis indicates that, with the exception of natural gas, fuel and grain supplies are not likely to limit the deployment of the major fuel switching technologies studied. In the case of natural gas, future supplies are too uncertain to make a definite judgment.

In this section, end-use equipment and, where appropriate, fuel delivery systems are examined in order to estimate the rate at which they can be installed and the oil replaced. The general procedure is to estimate the market penetration of each technology and determine the equipment

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[43] Note that this additional acreage cannot be accommodated solely with existing set-aside acreage. Additional set-aside acreage would be needed in order to stabilize year-to-year fluctuations in grain prices and in order for the corresponding farm price support programs to function. In fact, because the crop yields from the additional acreage under cultivation would fluctuate more from year to year than does average cropland, the average amount of set-aside acreage probably would have to increase in order to maintain the same overall stability in grain prices as exists now.

Calculating Ethanol's Energy Balance

Under the circumstances postulated for this study, the dominant consideration in determining potential oil replacement through ethanol production is the change in agricultural energy use resulting from supplying the ethanol feedstock and using the coproducts of the ethanol production. These changes include the direct energy needed to grow the feedstock (direct energy) and the reduced requirements for energy to grow the crops replaced by ethanol's coproducts (energy credit). But it also includes the changes in agricultural energy use resulting from shifts in crop production (e.g., less grain sorghum in one region and more in another) as the agricultural system adjusts to the increased demand for ethanol feedstocks (indirect energy).

For ethanol from corn, the agricultural use of oil and natural gas would increase by 40 to 150 percent of the energy content of the ethanol produced, depending on the specific types of crop production shifts that occur. For some other grains, the direct energy would be 20 to 25 percent less than for corn, but the increase in cropland acreage under cultivation needed to supply the feedstock would be considerably larger than that for corn. Consequently, the indirect energy could be greater, and the total increase in agricultural energy use could be similar to or perhaps larger than that for corn.

Because this study is primarily concerned with changes in national oil consumption, OTA has deducted the total increase in agricultural oil and gas use from the oil replaced directly by using the ethanol as a premium fuel. (Agricultural gas use is included because its use in agriculture precludes its use to replace oil in other sectors.) With the favorable assumption that agricultural oil and gas use would increase by 50 percent of the energy content of the ethanol, producing and using 5 billion gal/yr of ethanol would end up reducing U.S. oil consumption by 0.1 MMB/D.

Some proponents of fuel ethanol production, however, argue that this approach is not entirely appropriate because of the many high-valued products from corn (or other grains) that can be produced together with the ethanol (e.g., corn gluten and oil, beverage-grade carbon dioxide, furfural from corn cobs*). From this point of view, the increased agricultural energy use should be prorated among the various products in proportion to their economic prices. Thus, only a fraction of the increased agricultural energy use would be ascribed to the ethanol, and ethanol's net energy balance would appear to be more favorable. The remaining increase in agricultural energy use would then be ascribed to the increased economic activity associated with the sale and use of the coproducts.

The major problem with this procedure is that the apparent energy balance (which is supposed to be a physical measure) would change as relative prices change, even if the physical situation did not. Furthermore, regardless of how one allocates the energy "costs," the problem addressed in this report is to determine how much national oil consumption can be reduced. Because increased agricultural energy consumption is necessary to produce ethanol (and its coproducts), an analysis of changes in national oil consumption must consider the coproducts only to the extent that they reduce the need to produce other, oil-intensive products. This has been done for the case where the coproduct replaces animal protein concentrate; and, although the analysis has not been carried out for other possible coproducts (or combinations of them), it seems likely that such an analysis would not change the results significantly.

Consequently, if agricultural use of oil and gas increases by 50 percent of the energy content of the ethanol produced, then production of 5 billion gal/yr of ethanol and its immediate coproducts could reduce U.S. oil consumption by 0.1 MMB/D. The exact method of allocating energy "costs" among the various products is irrelevant to this result.

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*Corn sweetener is another high valued product from corn, but it is made from the starch in corn, which is the part converted to ethanol. Consequently, corn sweetener is an alternative to ethanol, not a coproduct.

and manpower needed to deploy that technology. Potential deployment rates are then estimated by comparing the equipment and manpower needs to historical production and fuel switching data and industry estimates of what could be accomplished in a crisis.

The starting point for this analysis is OTA's estimate of 1985 oil consumption by end-use category and sector. These estimates are shown in table 9 and are broken down into the Department of Energy regions shown in figure 25. The estimates are based on Energy Information Administration (EIA) projections[44] and data,[45] OTA's assessment of automobile fuel efficiency,[46] and OTA's judgment.[47]

Several categories of oil use are not included explicitly in table 9, because it would be particularly difficult to switch from these oil uses to alternatives within the 5-year time period considered in this assessment. These include aviation and marine fuels, petrochemical feedstocks, asphalt, petroleum coke, and lubricating oils.[48] However, the categories shown, which are the major can-

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[44] "1981 Annual Report to Congress," DOE/EIA-0173(81), May 1982.

[45] Data from Regional Councils submitted to Energy Information Administration under form EP-411, April 1983.

[46] *Increased Automobile Fuel Efficiency and Synthetic Fuels: Alternatives for Reducing Oil Imports* (Washington, DC: U.S. Congress, Office of Technology Assessment, OTA-E-185, September 1982).

[47] The major difference between EIA projections and the values shown in table 9 are in the electric utility sector. EIA assumed an average growth in demand of 3 percent between 1981 and 1985. However, since demand actually dropped between 1981 and 1982, demand would have to grow by 4.7 percent annually between 1982 and 1985 to arrive at EIA's 1985 projections. OTA, on the other hand, has assumed a 1.5 percent annual demand growth between 1982 and 1985. We have also assumed that the conversions and new powerplants plannned to be completed by 1985, as reported to EIA under form EP-411, will be completed by that date.

[48] Because of weight and space limitations, aviation fuel substitutes would be limited to high-grade synthetic fuels. Because of space limitations and, in some cases, boiler derating, substitutes for marine fuels would require synthetic fuels or extensive end-use modifications. Substitutions for petrochemical feedstocks and lubricating oils would have to be some forms of synthetic fuel. Although asphalt could be replaced by concrete and other materials, it would require extensive changes in paving and surface repair procedures. Moreover, petroleum coke is a normal byproduct of petroleum refining. Most of it is used for heat at the refinery, while the remainder is used for metallurgical purposes. Although the metallurgical coke could be replaced with high-grade coal, converting the coke to liquid fuels would be no easier than converting the coal to a synthetic fuel. Consequently, although substitutes exist for all of these uses of oil, the leadtimes for replacing large quantities of oil are likely to be considerably longer than 5 years, and, in some cases, the substitution makes little practical sense.

Table 9.—Estimated 1985 Oil Consumption by Region and End Use (thousand B/D)

		Region									
Sector	Total	1	2	3	4	5	6	7	8	9	10
Electric utilities:											
Distillate oil	50	a	a	15	10	10	10	a	a	a	a
Residual oil	590	175	170	50	80	15	a	a	a	95	a
Residential and commercial heat and hot water:											
Distillate oil	775	160	170	145	60	140	45	15	10	a	25
Kerosene	110	a	a	a	25	25	15	15	a	a	a
LPG	170	a	a	10	35	35	25	30	10	10	a
Residual oil	210	15	65	15	10	5	55	a	a	35	a
Industrial boilers:											
Distillate oil	250	35	80	25	25	25	35	10	a	10	a
Residual oil	710	90	150	65	160	75	120	a	20	15	10
Surface transportation and mobile industrial engines:											
Gasoline	5,700	270	445	555	1,065	1,130	755	335	215	720	215
Diesel	1,830	40	100	155	315	320	375	145	105	190	90
Subtotal	10,400	790	1,190	1,030	1,790	1,785	1,430	560	370	1,090	355
Other	5,600	—	—	—	—	—	—	—	—	—	—

[a] Less than 10,000 B/D.

SOURCE: Office of Technology Assessment.

didates for fuel switching, do include about 70 percent of the oil use projected for 1985.

In the following, each of the major end-use sectors is considered separately to derive estimates of the rate that oil replacement technologies could be deployed and the amount of oil that can be replaced. Electric utilities are considered first in order to provide estimates of the amount of electricity not generated by oil that could be available for fuel switching in other sectors. Heat and hot water in the residential and commercial sectors are considered next, followed by industrial boiler fuels and mobile engines for transportation and other uses.

Electric Utilities

In 1981, electric utilities consumed about 1.1 MMB/D of oil. Ninety-four percent of this, or slightly more than 1 MMB/D, was residual oil used in base and intermediate load utility boilers. The remainder, or about 60,000 B/D was distillate oil used in combustion turbines and diesel engines for peak electric generation. With a modest increase in demand for electricity (1.5 percent per year on average), utility residual consumption could drop to ~~0.6~~ MMB/D by 1985 as new nonoil-fired plants are brought on line, while the distillate use is likely to remain relatively constant.

Beyond 1985, as in the past, oil consumption by electric utilities will depend critically on the demand for electricity. Because oil is the marginal fuel for electricity generation in many regions, small percentage changes in the demand for electricity can result in much larger percentage changes in oil consumption. (For example, a 1.5 percentage point change in the annual demand growth for electricity between 1980 and 1985 would change the projected 1985 utility oil consumption by about 0.5 MMB/D.) It is notoriously difficult, however, to predict future demand; and the difficulties are compounded during times of rapidly changing energy prices such as those that would exist following a large oil shortfall. Consequently, for the purposes of this analysis, OTA performed the calculations using two different levels of change in demand for electricity. At the lower end, it was assumed that the depressed economic climate following the oil supply shortfall would result in relatively constant demand for electricity between 1985 and 1990. At the upper end, the estimates given by the North American Electric Reliability Council (NERC)[49] were used. NERC projected that demand for electricity will grow by about 2 percent per year, on average.

The major actions electric utilities can take to reduce their oil consumption are to switch to natural gas and coal and to complete construction of nonoil-fired powerplants that are currently under construction and scheduled for completion between 1985 and 1990.[50] The actual mix of actions taken will vary among the utilities and regions, but the broad outlines of a potential response can be discerned.

Utilities can begin almost immediately to use more natural gas in the boilers that are equipped to burn both oil and natural gas. OTA estimated the amount of this dual-fuel capacity from the 1981 utility fuel use profiles[51] by assuming that the powerplants that burned significant quantities of both oil and gas in 1981 but were not scheduled for retirement or conversion to other fuels by 1985 would be capable of burning both oil and gas in 1985. These estimates indicate that, of the regions consuming large quantities of oil for electric generation (table 9), regions 2, 4, and 9 have by far the most dual-fuel capacity. Regions 1 and 3 have only small amounts of dual-fuel capacity, and much of it is scheduled for retirement or conversion by 1985.

Based on 1981 oil consumption,[52] the dual-fuel boilers could replace about 60,000 B/D of oil in region 2, 75,000 B/D in region 4, and 65,000 B/D in region 9 within a short time, say 6 months, following an oil cutoff. This would require a total of about 0.4 TCF/yr of natural gas or the energy equivalent of 0.2 MMB/D. Although this is twice the 0.2 TCF/yr of surplus natural gas allocated to electric utilities (see section on "Natural Gas" under "Fuel and Grain Supplies"), later replacement of some of this gas through conversions to coal and so forth could bring the incremental utility consumption of gas down to its allocated level before the gas would be required by the commercial/residential and industrial sectors. Consequently, it would be possible for the electric utilities to use 0.4 TCF/yr of gas initially, without violating OTA's allocation of the assumed 2 TCF/yr of surplus natural gas.

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[49] "Electric Power Supply and Demand 1983-1992," North American Electric Reliability Council, Princeton, NJ, 1983.

[50] Another possibility is to construct new power lines from utilities with excess nonoil capacity to regions dependent on oil. The constraints here, however, are primarily institutional; and the uncertainties are large. Consequently, this option has not been included in OTA estimates.

[51] Data from Energy Information Administration form 759.

[52] Ibid.

Following this initial response, regional natural gas use will change as new gas pipelines are built, coal technologies are deployed, and new powerplants and interties are completed. It is probable, however, that gas prices will rise as a result of the increased demand for gas by utilities and other sectors; and much of the increased use of gas by utilities will eventually be replaced by other technologies.

A second type of fuel switching available to utilities is to convert oil-burning boilers to coal and coal water mixtures (CWMs) (see section on "Technologies"). Some utility boilers currently burning oil use coal as an alternative fuel and can switch quickly when oil prices rise, but the total amount of oil consumed in these boilers is not great.[53] Most oil-burning boilers will have to be modified to use solid fuels, either directly or as CWMs.

As explained in the section on "Technologies," the boilers that are suitable for conversion to solid fuels are those that were originally designed for coal but were subsequently converted to oil, and those that were originally designed for oil but are technically similar to coal-designed boilers. Of the boilers that are technically suitable for conversion, OTA assumed that only those that were brought into service on or after 1960 will actually be converted. This assumption reflects the fact that major investments are not likely to be made in the older generating plants because the remaining life of the facilities is too short to justify the expenditures. Based on these assumptions and the survey of utility boilers,[54] OTA identified 114 utility boilers in regions 1 through 4 and 9 that are suitable for conversion from oil to solid fuels.

Provided that the permits needed for the boiler conversion can be obtained in 10 months, a typical schedule for converting a utility boiler to solid fuel (including CWMs) might look something like that shown in figure 29.[55] A corresponding schedule for construction of a CWM preparation plant is shown in figure 30. CWM plant construction requires less time than boiler conversion; and because of this, the fraction of utility boilers that will convert to CWM as opposed to direct firing of the solid fuel does not have to be specified. Both conversions will require comparable leadtimes. As mentioned before, however, plants with limited space for coal-handling facilities would be more likely to convert to CWM.

Historically, the boiler industry has sold as many as 350 electric generating units to foreign and domestic utilities over a 5-year period;[56] and manufacturers of particulate control systems (to control particulate emissions) believe they can easily supply the necessary systems for 114 boiler conversions. Based on the historical rate, it is reasonable to assume that the conversion process could begin on half of the boilers during the first year after the onset of an oil shortfall, and the remaining half could be initiated the following year. The first boilers to be converted would then come on line a little over 2 years after the shortfall, and the conversions could all be completed within about 4 years.[57]

The generating capacity of facilities that can be converted from oil to coal (assuming that the converted boilers have 65 percent of the capacity

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[53] According to EIA data (Ibid.), electric utilities in region 3 consume the largest amount of oil in boilers that burn significant quantities of both oil and coal. The boilers in this region that were coal capable in 1981 and are not scheduled to be retired or replaced by 1985 consumed slightly less than 12,000 B/D of oil on average.

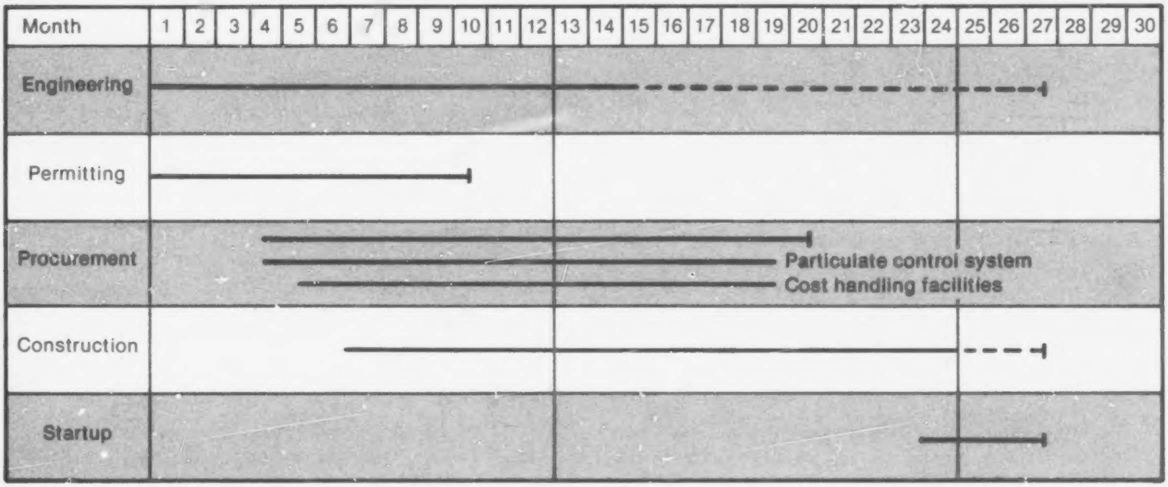
[54] "Survey of Oil-Fired Utility Boilers," op. cit.

[55] Test burns can often be carried out with considerably shorter leadtimes than those shown in figure 21. For full commercial conversion, however, more permanent and time-consuming modifications are needed.

[56] Gibbs & Hill, Inc., "Oil Replacement Analysis. Phase II," op. cit.

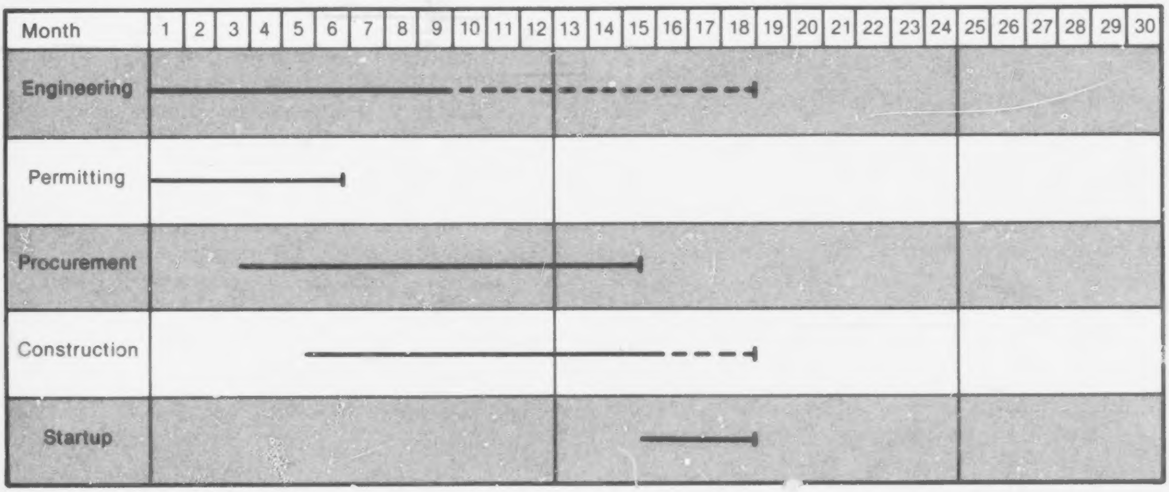
[57] To complete the conversions, the boiler would have to be out of operation for 3 to 6 months while the modifications in the boiler and (probably) needed repairs discovered when the boiler is opened are carried out. Generally, however, there is sufficient reserve capacity in utility systems to make up for the lost power as long as this phase of the conversion is carried out during the utility's off-peak season.

Figure 29.—Schedule for Engineering and Construction: Utility Boiler Conversion to CWM-Firing



SOURCE: Office of Technology Assessment.

Figure 30.—Schedule for Engineering and Construction: Central CWM Preparation Plant for Industrial Boilers



SOURCE: Office of Technology Assessment.

they had when burning oil) is shown in table 10, together with the capacity of new generating facilities scheduled for completion between 1985 and 1990. The new and converted capacity was then added to the 1985 nonoil-fired generating capacity to determine the total nonoil capacity in each region. This capacity was compared to peak winter and summer demands for the two levels of 1990 demand described above (fig. 31). The total amount of electric energy that could be generated by the nonoil-fired facilities (assuming 60 percent capacity factors for the new and converted capacity) was also compared to the 1990 demands for electricity.

Table 10.—Electric Generating Capacity of Facilities Converted From Oil to Coal and New Generating Capacity Scheduled for Completion Between 1985 and 1990

Region	Converted capacity[a] (MW)	New, nonoil capacity (MW)
1	4,427	3,484
2	6,321	3,730
3	5,331	3,730
4	5,199	20,098
5	—	12,286
6	—	15,088
7	—	1,702
8	—	1,718
9	6,080	10,949
10	—	2,979

[a] Assumes oil boilers converted to coal will be derated to 65 percent of the capacity they had with oil.

SOURCE: Office of Technology Assessment.

This analysis indicates that new capacity and coal conversions could replace most of the oil used by electric utilities by 1990, but small amounts would still be needed in regions 1 and 2, and Hawaii would still be primarily dependent on oil for electric generation. For the higher level of demand for electricity, a small amount of oil would also be needed in Florida and California (see fig. 31).[58]

In all, conversions to coal and new capacity additions could reduce utility oil consumption to about 0.05 to 0.1 MMB/D, depending on the demand for electricity. Natural gas could replace much of this remaining oil, except in Hawaii and possibly region 1. And the reductions in utility oil consumption might proceed something like that shown in table 11.

In order to estimate the amount of residential and commercial heating oil that could be replaced with electricity from excess nonoil-fired generating capacity, OTA assumed that this heating load would be centered around the utility's winter peak and that it would have an annual capacity factor of 35 percent. In other words, the total electric energy needed is the peak power demand times 3,060 hours, or 35 percent of the number of hours in a year. Peak winter demand (without the incremental home heating and hot water load) was subtracted from the total nonoil-fired capacity; and the excess capacity was converted to an equivalent amount of heating oil that could be replaced.

Based on this analysis, regions 1 and 2 and Hawaii would not have any excess nonoil-fired capacity for residential and commercial heating. In all other areas, however, the excess nonoil-fired capacity would be adequate by 1990 to replace all of the residential and commercial heating oil not replaced by natural gas (see below). But region 3 and Florida would be marginal cases; and, if other demand for electricity increases at the rate projected by NERC[59] (about 2 percent per year), utilities in these regions might be faced with peak demands which slightly exceed the nonoil-fired capacity available through conversion to coal and completion of new powerplants currently under construction. Therefore, these utilities may also have to convert some (otherwise unneeded) oil capacity to natural gas or delay retirement of some dual fuel capacity in order to supply the increased demand (including home heating) without using oil. Furthermore, although California utilities might still be using small amounts of oil during their summer peak, nonoil capacity would be adequate to accommodate the increased load during the winter peak without increasing their oil consumption.

In short, through conversions to coal and completion of new powerplants, together with a small increase in natural gas use, utilities could eliminate virtually all of their oil use by 1990, except in Hawaii and possibly region 1. Furthermore, these conversions could provide sufficient excess nonoil-fired capacity to replace all of the residen-

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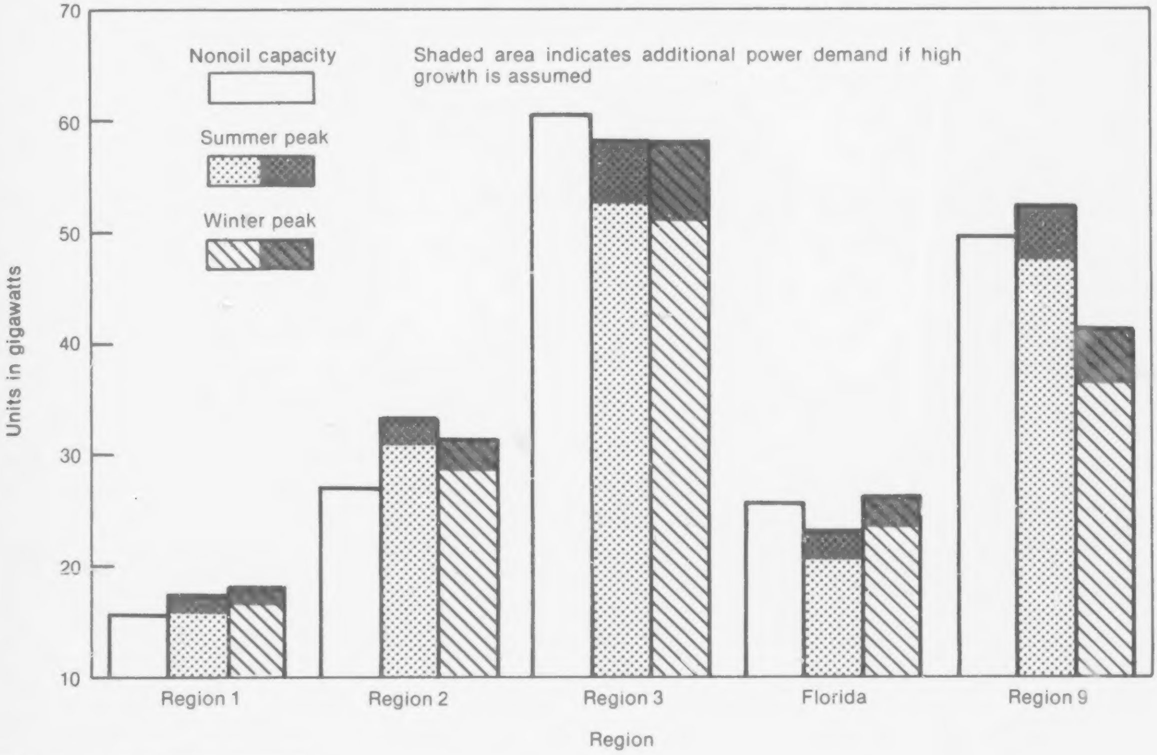
[58] The methodology used was to assume that the peak demand curve is triangular. The amount of oil-fired capacity needed was then estimated by subtracting the nonoil-fired capacity from the peak demand. The amount of oil consumed would then be the area of the triangle, whose height is the amount of oil-fired capacity needed. Consequently, the ratio of 1990 oil consumption to 1985 oil consumption was estimated as the square of the ratio of the amount of oil-fired capacity needed at peak demand in 1990 to that needed in 1985. This methodology overestimates the 1990 oil consumption in those regions where there is significant oil-fired baseload capacity used in 1985, but the resultant estimates of 1990 oil consumption are sufficiently small that this problem is not significant. The methodology does not, however, result in an estimate that oil is needed in a region where it in fact would not be. The amount of oil that could be replaced was also double-checked by assuming that the new and converted capacity would operate at an average 60 percent capacity factor, and in all cases the new and converted capacity was more than adequate to replace the oil.

[59] North American Electric Reliability Council, op. cit.

Figure 31.—Potential Nonoil-Fired Electric Generating Capacity and 1990 Peak Electric Demand for Selected Regions



SOURCE: Office of Technology Assessment.

Table 11.—Potential Utility Oil Consumption With Conversion to Natural Gas and Coal (thousand B/D)

Region/year	1985	1986[a]	1987	1988	1989	1990
1	175	175	139	62	41	41
2	169	109	67	b	b	b
3	63	63	45	19	b	b
4	89	14	b	b	b	b
5	28	28	18	10	b	b
6	15	15	b	b	b	b
7	b	b	b	b	b	b
8	b	b	b	b	b	b
9	98	33	28	20	16	16
10	b	b	b	b	b	b

[a] The sharp drop is due to switching to natural gas in dual fueled boilers.
[b] Less than 10,000 B/D.
[c] Assumes half of the oil used for electric peaking is replaced by natural gas within 2 years.

SOURCE: Office of Technology Assessment.

tial and commercial oil not replaced by natural gas, except in regions 1 and 2 and Hawaii.

The above results are particularly sensitive to actual developments in regions 1 and 2, however. Delays in conversions or completion of powerplants currently under construction could increase oil consumption in these regions significantly. On the other hand, construction of new power lines and increased purchases of electricity from Canada and region 5 would reduce these regions' oil dependence and possibly provide some excess capacity for residential and commercial space heating and hot water.

Residential and Commercial Space Heat and Hot Water

Almost 1.3 MMB/D of oil was consumed in 1981 for space heating and hot water in the residential and commercial sectors. Over 60 percent of this, or 0.8 MMB/D, was distillate fuel oil. The remainder was divided among LPG (0.2 MMB/D), residual fuel oil in commercial buildings (0.2 MMB/D), and kerosene (0.1 MMB/D).[60] Although demand for oil in these sectors dropped slightly in 1982 and 1983, it is unclear how much was due to short-term behavioral changes and how much was due to fuel switching and increased efficiency. Consequently, for the purposes of this analysis, OTA made the conservative assumption that residential and commercial demand for these fuels will be about the same in 1985 as it was in 1981.

The major fuel switching options open to the residential and commercial sectors are conversions to natural gas, electricity (where surplus nonoil-fired capacity exits), and solid fuels. Natural gas conversions are considered first, followed by conversions to electricity. Conversions to solid fuels are then examined for the regions where the combination of gas and electricity cannot replace all of the oil use within 5 years.

Conversion to Natural Gas

In 1980, about 14 million households in the United States used fuel oil or kerosene for heat.[61] About 36 percent of these are in rural areas,[62] which are generally too far from existing natural gas lines and where the population densities are too small to justify the cost of constructing distribution lines to these houses. Similarly, most of the households using LPG are located in rural areas and are not candidates for conversion to natural gas.

Many of the urban households that use oil for heating, however, are already connected to gas lines and use gas for hot water and/or cooking; and most of the others are located near existing gas lines. If 80 percent of the urban households could be converted to gas, about half of all residential users of fuel oil and kerosene could convert. If we assume a similar market penetration for commercial users of these fuels, conversions from oil to gas could replace about 0.44 MMB/D of oil (see table 9).

These conversions to natural gas would require the installation of about 7 million burners in residential households and about 1 million burners in commercial establishments, together with about 1 million new boilers where the old oil-fired ones required replacement.[63] In addition, about 5 million customers would require the installation of new distribution lines, while 2 million to 3 million are already connected to gas lines.[64]

Current production capacity for natural gas burners is about 1.5 million units per year;[65] and the highest historical rate for connecting new gas customers is about 1 million per year. Consequently, with only a modest growth in these rates, all of the potential gas customers could be supplied with new distribution lines (where needed) and gas burners within about 4 to 5 years. With this rate of deployment, new gas boilers would not be a constraint, since current production capacity is about 0.4 million units per year[66] and the needed supply could be provided within 2.5 years.

In addition to these generic constraints, gas use for heating in New England (region 1) is currently limited by the pipeline capacity. During the winter peak, the two main pipelines to the region generally operate at full capacity; and new trunk pipelines will have to be built to accommodate the increase in gas used for space heating. Although the additional capacity can be built in about 1 year along existing pipeline rights of way, assuming no permitting delays,[67] this construction probably will have to precede any significant replacement of oil by gas in the residential and commercial sectors in region 1. Trunk pipeline capacity does not seem to be a constraint in other regions, however.

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[60] EIA "Annual Report to Congress," op. cit.

[61] "Residential Energy Conservation Survey: Housing Characteristics 1980," DOE/EIA-0134, June 1982; and "Residential Energy Consumption Survey," DOE/EIA-0262/1, April 1981.

[62] Ibid.

[63] Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase I," op. cit.

[64] Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase II, op. cit.

[65] Ibid.

[66] Ibid.

Because of the difference in the potential deployment rate in New England and that in other regions, it is necessary to derive a regional distribution for this new natural gas use in order to determine the national deployment rates. Owing to regional differences in electricity generating facilities, this regional break down is also necessary to assess the oil replacement potential from electricity considered below. In order to derive this distribution, OTA assumed that the increase in gas use in each region would be proportional to 1980 gas consumption in the residential/commercial sectors in that region, or 100 percent of the urban use of fuel oil and kerosene in that region, whichever is less. This methodology is based on the premise that regions with a larger current gas use have a more developed infrastructure (manpower, distribution system, and equipment) and, therefore, will be able to connect a larger number of new customers in a given time.

With these assumptions, the increase in gas use for space heating and hot water in each region is shown in table 12. And, based on a 1-year delay before conversions begin in New England, 4 years to make the end-use conversions (once they begin), and the regional market penetration in table 12, natural gas replacement of heating oil and kerosene could proceed something like that shown in table 13.

Table 12.—Potential Increase in Natural Gas Use for Space Heating and Hot Water

Region	Potential increase in natural gas use (thousand B/D oil equiv.)	Increase relative to 1980 demand (%)
1	26	24
2	80	24
3	83	24
4	53	18
5	105	9
6	37	10
7	22	7
8	10	7
9	9	2
10	15	24
Total	440	12

SOURCE: Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase II—Evaluation of Selected Technologies," contractor report to OTA, August 1983.

Table 13.—Potential Reduction in Oil Use in the Residential and Commercial Sectors Through Conversion to Natural Gas, Electricity, and Solid Fuels (thousand B/D)

	Year				
Fuel	1986	1987	1988	1989	1990
Natural gas	40	180	380	440	440
Electricity	110	220	335	445	455
Wood and coal	15	35	50	65	80
Total	165	435	765	950	975
Remaining oil consumption	1,095	825	495	310	285

SOURCE: Office of Technology Assessment.

Conversion to Electricity

Most of the remaining residential and commercial oil customers in regions 3 through 10 (except Hawaii) would be candidates for conversion to electricity for space heat and hot water. (Regions 1 and 2 are excluded from these conversions because there would not be excess nonoil-fired capacity to supply the electricity.) In some rural areas, new power lines would have to be constructed to accommodate the increased load; for some of the remaining oil customers, the cost of new power lines would be prohibitive. Assuming that 40 percent of the rural oil customers (taken to be 36 percent of the distillate and kerosene customers plus all of the LPG customers) would need new power lines and that half of these lines would not be built, customers consuming about 40,000 B/D of oil in regions 3 through 10 would not convert to electricity; but customers consuming a little over 0.4 MMB/D would be candidates for conversion to electricity.

Excluding the oil customers in regions 1 and 2, those OTA assumed would convert to natural gas, and those located too far from adequate power lines, a little over 8 million customers could convert to electricity. Of these customers, about 35 percent or 3 million also used oil for hot water.[68] Consequently, the switch to electricity would require space heating for 8 million households and commercial establishments and about 3 million electric hot water heaters.

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[67] Ibid.

In 1980, about 13.4 million portable electric heaters and 2.8 million fixed electric baseboard heaters were shipped.[69] If manufacturing facilities for these devices were operating at 70 percent of capacity in 1980, current manufacturing capacity could supply 19 million space heaters and 4 million baseboard heaters per year.

Furthermore, it has been estimated that, in 1981, about 0.5 million central heat pumps (for heating) and 1.5 million central air-conditioning systems were installed.[70] Because of the similarity between heat pumps and air-conditioners, manufacturers of central air-conditioners could easily convert to making heat pumps. If manufacturing facilities were operating at 70 percent of capacity and one-third of the air-conditioner manufacturers can convert to heat pump manufacturing, about 1.5 million central heat pumps could be manufactured and installed per year. By an analogous reasoning process, 1981 installations of unitary (window-mounted) heat pumps and air-conditioners (estimated at 0.5 million and 3.7 million, respectively[71]) imply a production capacity of 2.5 million unitary heat pumps per year.

Between 1970 and 1980, the number of households with hot water heaters increased by 17 million; and the number with electric hot water heaters increased by 10 million.[72] In addition, an unknown number of hot water heaters were installed as replacements for existing heaters; and many of the manufacturers of nonelectric units could easily convert to produce electric units. Consequently, the production capacity for electric hot water heaters is probably at least 2 million units per year, and perhaps considerably larger.[73]

If 50 percent of the customers converting to electricity go to central heat pumps, 25 percent go to unitary heat pumps (4 to 5 units per customer), and the remaining needs are supplied by electric resistance heating, the necessary equipment for the 8 million space heating conversions could be supplied in less than 4 years; and the 3 million hot water heaters could easily be supplied in this time or less. If the equipment were installed within 4 years in each region, the oil replacement by electricity could proceed like that shown in table 13. If, however, more electric resistance heating were used, the initial oil replacement could be somewhat greater than that shown in the table. For example, if 75 percent of the customers go to electric resistance heating, over 70 percent of the total oil replacement shown for 1990 could be achieved by 1987.

Conversion to Solid Fuels

A third option open to residential and commercial oil users is to switch to solid fuels, primarily wood and coal. This option is most important in regions 1 and 2 because of the large supplies of wood and the lack of other options for residential and commercial customers. For these reasons switching to solid fuels is considered in detail for these regions. Elsewhere, however, most of the oil could be replaced by switching to natural gas and electricity. Consequently, while a detailed consideration of solid fuel switching would increase the initial rate that oil is replaced in regions 3 through 10,[74] it would not significantly affect the total amount of oil replaced by 1990. Therefore, for the purposes of this analysis, OTA has simply assumed that half of the remaining residential and commercial oil use in regions 3 through 10, or about 20,000 B/D, could be replaced with solid fuels.

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[68] This assumes that the proportion of commercial oil customers who use oil for both heat and hot water is the same as it is for residential oil customers.

[69] "Selected Heating Equipment," MA34N, U.S. Bureau of the Census.

[70] Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase I," op. cit.

[71] Ibid.

[72] "Housing Characteristics," U.S. Bureau of the Census, 1970; and "Provisional Estimate of Social, Economic and Housing Characteristics," PHC 80-51-1, 1980.

[73] Ignoring replacements and assuming that half of the manufacturers of nonelectric hot water heaters converted to the production of electric heaters and that the manufacturing facilities operated at 70 percent of capacity during the 1970s, current production capacity would be 1.35 ÷ 0.7 = 1.9 million units per year.

[74] Between 1978 and 1980, the years when residential and commercial use of wood increased the fastest, wood energy use in these sectors increased by the equivalent of about 40 MB/D (thousand barrels per day) annually in regions 3 through 10 (EIA, "Estimates of Wood Energy Consumption 1949 to 1981," op. cit.). At the same time coal consumption in these sectors dropped by the equivalent of 15 MB/D annually. Ignoring the drop in coal consumption and assuming that this rate of wood use increase could be doubled and that wood heating is half as efficient as oil heating, then the total oil replacement shown in table 13 could be increased by about 35 MB/D in 1986, 70 MB/D in 1987, and 105 MB/D in 1988 through inclusion of this rate of switching to wood in regions 3-10. The 1989 and 1990 totals, however, would be unaffected.

Historically, the largest increase in the use of wood in the residential and commercial sectors occurred between 1978 and 1980 and amounted to the energy equivalent of about 4,000 B/D annual increase in each of regions 1 and 2.[75] Assuming that this rate of increase in wood use could be doubled and that wood heating is half as efficient as oil heating, then wood could replace an additional 40,000 B/D of oil in regions 1 and 2.

Although national coal use in the residential and commercial sectors has declined each year since at least 1950, coal consumption by these sectors in regions 1 and 2 experienced a 1-year increase around 1980 by the energy equivalent of 1,000 B/D of oil in region 1 and 3,000 B/D in region 2.[76] Assuming this annual increase could be doubled and that coal heating is equivalent to wood heating in efficiency, then coal could replace another 20,000 B/D of oil within 5 years.

As shown in table 13, inclusion of solid fuel conversions would increase the amount of oil replaced by about 80,000 B/D in 1990. Although the total increase in the use of solid fuels could be larger, most of the additional use above 80,000 B/D would probably be a substitute for or an addition to conversions to natural gas and electricity in regions 3 through 10.

The above analyses indicate that, within 4 years after the onset of an oil supply shortfall, fuel switching could virtually eliminate the use of oil for space heating and hot water in most regions of the country. Replacing all of the oil used by the residential and commercial sectors in regions 1 and 2, however, would take considerably longer, owing to the heavy dependence on oil of these sectors and electric utilities in the regions.

Industrial Boilers

In 1980, the industrial sector consumed about 0.7 MMB/D of residual fuel oil, mostly as a boiler fuel, and another 0.2 MMB/D of distillate fuel oil for a variety of heat purposes, including process heat and some boiler fuel.[77] [78] By 1982, residual use dropped to 0.5 MMB/D and distillate use also dropped slightly.[79] For the purposes of this study, however, OTA assumed that, with some economic recovery, industrial use of these fuels will return to their 1980 values by 1985.

The major replacements for oil used as a boiler fuel are solid fuels (direct combustion and gasification of coal and wood and CWMs) and natural gas.[80] Conversions to solid fuels are considered first, followed by estimates of the rate that the available natural gas could replace the remaining oil use in industrial boilers.

Conversion to Solid Fuels

In 1979, there were about 146,000 oil-fired industrial boilers in the United States, of which nearly 142,000 had a capacity of less than 50 MMBtu/hr.[81] Nevertheless, almost half of the oil used as boiler fuel was consumed in the 4,000 boilers over 50 MMBtu/hr, and by 1985 these boilers will consume an estimated 0.4 MMB/D.

Assuming that half of the oil consumed in the larger (greater than 50 MMBtu/hr) boilers could be replaced with solid fuels[82] [83] and that the average boiler being replaced or converted had a capacity of 135 MMBtu/hr and operated at a 35 percent capacity factor, then about 1,000 large boilers would have to be replaced or converted.[84] Historically, the highest annual sales of 100 to 250 MMBtu/hr boilers was 248 units in 1973.[85] In this size range, however, most **solid fuel** boilers are field-erected, for which the historical high was 57 units sold in 1969; but the major boiler manufacturers estimate that, at full capacity and with considerable duplication of engineering designs, up to 550 boilers could be field-erected within 3 to 4 years.[86] In addition, many of the boilers could be converted to burn solid fuels or CWMs directly or could be equipped with gasifiers; and the manufacturing constraints are considerably less severe for these types of conversions. In these cases, additional "slide along" boilers would be needed to make up for the lost capacity resulting from boiler derating. However, these would be smaller, prefabricated boilers, for which production capacity is about 1,100 units per year.[87]

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[75] EIA, "Estimates of Wood Energy Consumption 1949 to 1981," op. cit.

[76] "State Energy Data Report," U.S. Department of Energy, DOE/EIA-0214(81), June 1983.

[77] Total industrial consumption of distillate fuel oil was about 0.7 MMB/D in 1980. However, OTA assumed that 90 percent of the distillate used in the nonmanufacturing sectors was used for mobile engines such as in off-road construction, mining, and agricultural equipment and machinery. The fuel used by these mobile engines are included in the next section, together with oil consumption for transportation.

[78] EIA, "1981 Annual Report to Congress, op. cit.

[79] "1982 Annual Energy Review," U.S. Department of Energy, DOE/EIA-0384(82), April 1983.

[80] In addition, since some of the steam from boilers is used for mechanical drive, a portion of the boiler fuel could be replaced with electric motors, but OTA has not analyzed this option.

[81] "Population and Characteristics of Industrial Boilers in the U.S.," U.S. Environmental Protection Agency, EPA/600/7-79-178-A, August 1979.

[82] Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase II," op. cit.

[83] See also P. C. Kurtzrock, "Planning Objectives," proceedings of the Coal-Water Fuel Technology Workshop, BNL-51427, Mar. 18-21, 1981.

Regardless of whether the boilers are replaced or converted, each system would require a particulate control system (PCS) to limit particulate emissions. Historically, the largest number of PCSs sold was 200 units in 1980; but the Industrial Gas Cleaning Institute estimates that 1,000 units could be produced in about 3 years.

Based on these production capacities, it appears that 1,000 large industrial boilers could be converted to solid fuels in about 3 to 4 years. Assuming 4 years and the engineering and construction schedules shown in figures 32 and 33, replacement of oil by solid fuels in large industrial boilers could proceed something like that shown in table 14.

As indicated above, solid fuel boilers to replace the smaller industrial oil-fired boilers could be manufactured at a rate of about 1,100 units per year, and perhaps 5,000 boilers could switch in 5 years.[88] Assuming that one-quarter of the small (less than 50 MMBtu/hr) boilers consume half of

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[84] These assumptions reflect the fact that, of the boilers for which conversion is technically feasible, the boilers consuming the largest amounts of oil are most likely to be converted.

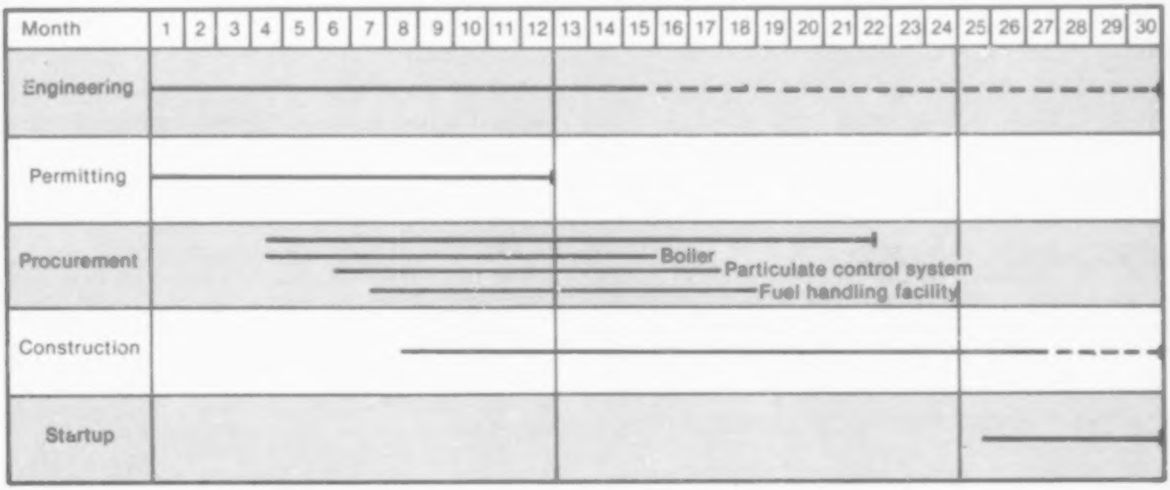
[85] Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase II," op. cit.

[86] Ibid.

[87] The recent historical high for the sales of 10 to 100 MMBtu/hr solid fuel boilers was 100 units in 1973. However, manufacturers of gas and oil boilers could easily convert their facilities to produce solid fuel boilers; and when these are included, the historical 1 year high is 800 boilers. Assuming that this is 70 percent of peak capacity, then the latter is 1,100 units per year.

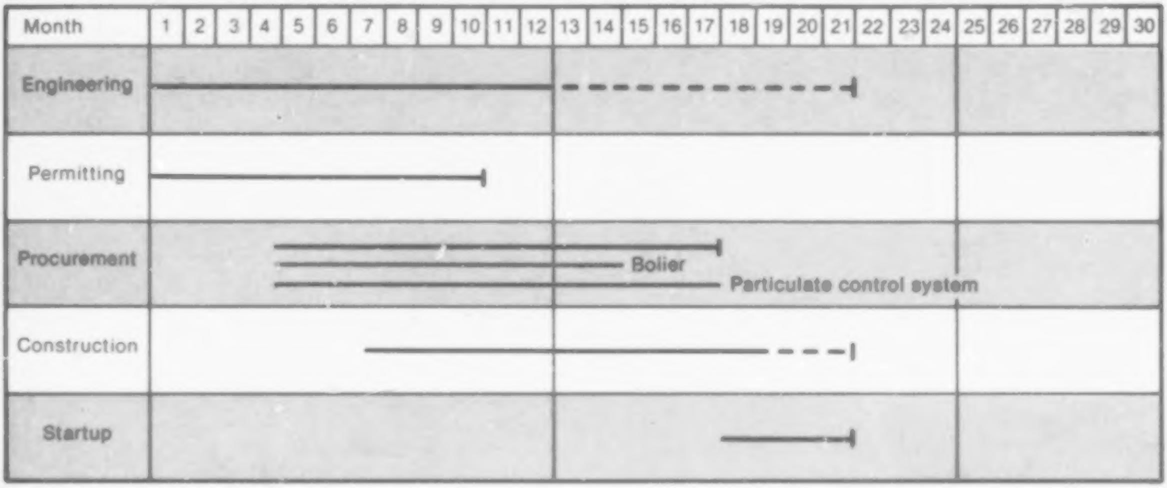
[88] This assumes that 500 of these boilers would be needed in conjunction with the large boiler conversions, in order to compensate for derating.

Figure 32.—Schedule for Engineering and Construction: Coal- or Wood-Firing Steam Generating System, Fuel-Handling Facilities, and Particulate Control System



SOURCE: Office of Technology Assessment

Figure 33.—Schedule for Engineering and Construction: Industrial Boiler Conversion to Solid Fuels



SOURCE: Office of Technology Assessment.

Table 14.—Potential Reduction in Oil Used in Industrial Boilers Through Conversion to Solid Fuels and Natural Gas (thousand B/D oil)

	Year					
Fuel	1985	1986	1987	1988	1989	1990
Solid fuels	—	0	40	90	150	200
Natural gas	—	190	330	420	445	455
Total	—	190	370	510	605	655
Remaining oil consumption in industrial boilers	960	770	590	450	355	305

SOURCE: Office of Technology Assessment and Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase II—Evaluation of Selected Technologies," contractor report to OTA, August 1983.

the oil used in small boilers, an additional 0.04 MMB/D of oil could be replaced by solid fuels.[89] The inconvenience of using solid fuels, however, could limit the number of small boiler conversions to considerably less than this number.

Conversion to Natural Gas

The other major option is to convert industrial boilers to natural gas. Based on OTA's allocation of the assumed quantities of natural gas, the industrial sector could increase its gas use by the equivalent of about 0.45 MMB/D of oil. If the new gas customers consume, on average, the same amount of gas per customer as current industrial gas users (i.e., 42 billion Btu/yr[90]), this increment of natural gas use would require approximately 22,000 new customers.[91]

In 1981, there were 187,900 industrial gas customers, down from 209,100 in 1973.[92] Many of these customers switched back to oil while retaining the ability to reconvert quickly to gas. In addition, the number of industrial gas customers grew by 5,000 to 7,000 customers per year in the late 1960s. This indicates that, even if some new distribution lines must be built, the 20,000 industrial customers could probably be converted to gas in 2 to 3 years. Assuming 2.5 years for the conversions, the rate of oil replacement by natural gas could look something like that shown in table 14. Furthermore, it is clear that more oil could be replaced if natural gas supplies are greater than those assumed, but the rate of oil replacement would taper off as more conversions would be needed for each additional increment of oil replaced.

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[89] One-quarter of the boilers would be 35,500 boilers. Assuming these boilers use 0.25 MMB/D of oil, then 5,000 boilers would use approximately 0.035 MMB/D.

[90] "Gas Facts," American Gas Association, Department of Statistics, Arlington, VA, 1981.

[91] An alternative way to derive the number of new customers is as follows. Assume that all of the 3,000 large boilers not converted to solid fuels convert to gas. These boilers would consume about 44 percent of the gas increment, or the equivalent of 0.2 MMB/D of oil. If one-quarter of the small gas boilers consume half of the remaining 0.5 MMB/D of oil targeted for replacement, then the remaining 0.25 MMB/D equivalent of gas allocate to industry would involve 142,000 ÷ 4 = 35,500 boilers. Many industrial concerns with small, package boilers have several boilers in parallel and/or reserve boilers to improve system reliability. Assuming two boilers per customer, on average, the total number of new gas customers would be 35,500 ÷ 2 + 3,000 = 20,750.

[92] "Gas Facts," American Gas Association, op. cit.

This analysis indicates that almost 0.7 MMB/D of oil used in industrial boilers could be replaced with solid fuels and natural gas within 5 years after an oil supply disruption. About 65 percent of the total would be replaced by the increased natural gas supplies that OTA assumes will be available to industry. Clearly, the actual oil replacement will depend critically on the quantity of surplus gas that actually materializes.

Mobile Engines

In 1980, highway transportation consumed about 6.3 MMB/D (oil equivalent) of gasoline and 0.9 MMB/D of diesel fuel. The gasoline went primarily to automobiles (4.6 MMB/D) and trucks (1.7 MMB/D), while trucks consumed 92 percent of this diesel fuel.[93] Nonhighway transportation consumed an additional 2.0 MMB/D of oil, primarily as jet fuel (0.8 MMB/D), residual fuel oil in ships (0.7 MMB/D), and diesel fuel in trains (0.3 MMB/D).[94] In addition, off-road vehicles and equipment in construction, mining, and agriculture (the industrial sector) consumed an estimated 0.5 MMB/D.[95]

By 1985, increased fuel efficiency in automobiles and light trucks is likely to reduce gasoline consumption to around 6 MMB/D,[96] while the other categories are likely to be similar to their 1980 values.

The principal technologies studied for replacing the oil used in mobile engines are ethanol production and conversions to compressed natural gas (CNG), liquefied petroleum gas (LPG), and mobile gasifiers. These substitutes are best suited to spark ignition (gasoline) engines, although they can be adapted to diesel engines. Ethanol can also be used as a fuel for jet engines, but its lower energy density (energy per unit weight) as compared to jet fuel and the need for extensive testing to ensure safety are likely to limit its use severely in jets in the near future. It is not necessary, however, to specify the exact end uses, since the potential for these alternatives is quite limited relative to the amount of fuel consumed by mobile engines.

Ethanol Production

A 50 million gal/yr ethanol distillery can be constructed in about 2 years, as shown in figure 34. Each distillery would require a 250 to 300 MMBtu/hr boiler and particulate control system identical to those discussed in the previous section. To the extent that this equipment is supplied to ethanol distilleries, the supply for industrial boiler conversions would be reduced; and both types of activities could be delayed somewhat. Each distillery, however, would also require 3 to 5 centrifuge decanters with capacities of 250 to 400 gallons per minute.[97] Production capacity for centrifuges is proprietary, but one leading supplier indicated that, in an emergency, perhaps 500 steel castings could be obtained over a 5-year period.[98] With an average of four centrifuges per distillery and a 1-year delay after the equipment procurement before the final distillery becomes operational, perhaps 100 ethanol distilleries could be completed in 5 years. At this rate of construction, the boilers, particulate control systems, and other equipment needed for the distilleries could probably be obtained without significant delays.

One hundred ethanol distilleries of this size would produce 5 billion gallons of ethanol annually, with an energy content of about 0.2 MMB/D. Because of the energy used in agricul-

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[93] G. Kulp and M. C. Holcomb, "Transportation Energy Data Book, Sixth Edition," Oak Ridge National Laboratory, Oak Ridge, TN, ORNL-5883, 1982.

[94] Ibid.

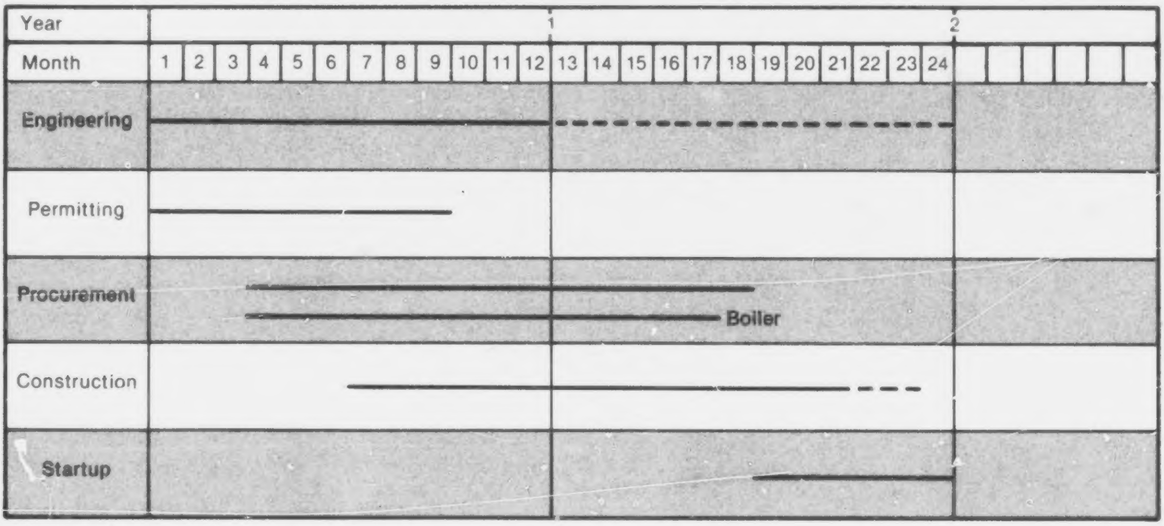
[95] Assuming that 90 percent of the distillate and gasoline used in mining and construction was for mobile engines.

[96] This assumes that the average fuel efficiency of new cars sold in 1985 will be 27.5 mpg and that the percentage efficiency increase in light trucks on the road will be half as large as for automobiles. Also, between 1979 and 1980, gasoline consumption dropped by 0.5 MMB/D; and OTA estimates that 0.3 MMB/D of this drop was due to people driving less. The 1985 estimate for gasoline consumption, however, assumes that driving levels would have returned to extrapolations of the pre-1978 levels. See also *Increased Automobile Fuel Efficiency and Synthetic Fuels: Alternatives for Reducing Oil Imports* (Washington, D.C.: U.S. Congress, Office of Technology Assessment, OTA-E-185, September 1982.) (Note, however, that in the latter report, 1 barrel of oil equivalent is equal to 5.9 MMBtu, while in the current report it is taken equal to 5.5 MMBtu.)

[97] Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase II," op. cit.

[98] Ibid.

Figure 34.—Schedule for Engineering and Construction of a 50 Million Gal/yr Ethanol Plant



SOURCE: Office of Technology Assessment.

ture to supply the grain feedstock for the distilleries, however, this ethanol would probably replace less than 0.1 MMB/D of oil, net (see app. B). Based on these estimates, oil replacement by ethanol could proceed as shown in table 15.

Conversion to Compressed Natural Gas

The analysis of vehicle conversions to CNG indicates that the factor limiting the rate of conversions is most likely to be the availability of natural gas compressors. A typical compressor with a capacity of 20 standard cubic feet per minute (scfm) could service about 20 vehicles, with slow fill (10 hour) for 15 of the vehicles and fast fill (3 to 5 minutes) for the remaining 5. Larger fleets of vehicles would typically be serviced with multiples of this arrangement,[99] although they could use somewhat larger compressors. If the compressor operates at full capacity an average of 10 hours per day, 5 days a week, each compressor could deliver about 3 billion Btu of CNG per year.

Table 15.—Potential Reduction in Fuel Use in Surface Transportation and Mobile Industrial Engines (thousand B/D oil)

	Year					
Fuel	1985	1986	1987	1988	1989	1990
Ethanol	—	0	25	50	75	100
CNG[a]	—	8	16	24	32	40
LPG[b]	—	40	40	40	40	40
Mobile gasifiers	—	0	0	50	100	100
Total[c]	—	48 (48)	81 (121)	164 (244)	247 (367)	280 (440)
Remaining gasoline and diesel fuel consumption	7,530	7,480	7,410	7,290	7,160	7,090

[a] Compressed natural gas.
[b] Liquefied petroleum gas.
[c] Number in parenthesis indicates potential increase in LPG consumption in vehicles. However, at most 40,000 B/D would be from new production; the remainder would be a shift in LPG from stationary uses.

SOURCE: Office of Technology Assessment.

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[99] Ibid.

In 1980, 5,512 gas compressors were shipped, which is close to the historical high of 5,770 units in 1974.[100] Assuming that manufacturing facilities were operating at 70 percent of capacity, then an additional 2,400 compressors per year could be manufactured.[101] If 2,000 of these could be manufactured to the specifications needed for CNG vehicle refills and the production increased by 50 percent per year,[102] then about 26,000 CNG compressors could be delivered in 5 years. These compressors could provide enough CNG to replace about 0.04 MMB/D of oil with the deployment shown in table 15. If larger fleets use larger compressors, the total replacement could be increased somewhat; but in light of the optimistic assumptions about compressor availability, it seems clear that the total potential from CNG is small.

Conversion to Liquefied Petroleum Gas

As outlined in the section on "Fuel and Grain Supplies," an incremental production of 2 TCF/yr of natural gas would result in about 0.04 MMB/D oil equivalent of LPG suitable for internal combustion engines; and this would be sufficient to fuel about 1 million vehicles. The analysis of vehicle conversions indicates that about five times this many vehicles could be switched to LPG over a 5-year period.[103] Nevertheless, the full conversion capacity could be needed if the 0.16 MMB/D of LPG replaced from the residential and commercial sectors is to be used as a vehicle fuel. Only the new LPG production, however, would replace oil; the remainder would simply be a transfer of petroleum used in one sector to another. Consequently, the oil replacement potential would be limited by the rate that new LPG could be produced. Based on the previous analyses of new natural gas use, the oil replacement by LPG vehicles could develop as shown in table 15. To the extent that the natural gas is imported or made available through fuel switching and conservation, however, the LPG would have to be obtained from sources outside of the United States, which would be roughly equivalent to importing more oil.

Conversion to Mobile Gasifiers

The final technology considered is the mobile gasifier. The analysis of this technology indicates that the components needed for mobile gasifiers are so common that several million units could be produced annually, following an initial 2-year delay to establish standard designs and complete fleet tests.[104] Consequently, after the initial period it is likely that gasifier deployment would be limited by the potential market for these devices.

In Sweden during World War II, the market penetration of mobile gasifiers reached 30 percent of the automobiles (but later dropped to 10 percent), 55 percent of the trucks, and 70 percent of the buses;[105] but this is probably much larger than could be achieved in the United States today. Assuming that gasifiers, on average, replace half of a vehicle's fuel needs and that market penetration reaches one-fifth of that in Sweden during World War II, then mobile gasifiers could replace about 0.1 MMB/D of oil. The oil replacement by mobile gasifiers could then proceed as shown in table 15. These estimates, however, are highly speculative.

This analysis of fuel switching in mobile engines indicates that perhaps 0.2 to 0.3 MMB/D of oil could be replaced, but the constraints are quite severe. Ethanol, which can be used with the least amount of end use difficulty, is derived from energy-intensive agricultural feedstocks. As agricultural production expands, the energy (per unit ethanol) consumed in supplying the feedstock increases; and the net oil savings drops. CNG use is constrained by the availability of gas compres-

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[100] "Pumps and Compressors," Current Industrial Reports, MA35P, U.S. Department of Commerce, Bureau of the Census, December 1981.

[101] In contrast to this, over 1.5 million air compressors were shipped in 1980 (Ibid.). However, natural gas compressors are far more complex than air compressors because of stricter sealing requirements, higher pressures, and the need for intercoolers, condensate traps, and precautions against sparking. The air compressor manufacturing capacity, therefore, cannot be used to judge production capacity for CNG compressors.

[102] This corresponds to an 11-percent annual increase in production capacity for all gas compressors with all of the increase going to natural gas compressors. This may be overly optimistic in view of the historical 3.1-percent annual increase in industry sales over the past 20 years (Ibid.) and the long leadtime for some items needed to manufacture gas compressors (Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase II," op. cit.).

[103] Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase II," op. cit.

[104] Rasor Associates, op. cit.

[105] Ibid.

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Mobile gasifiers can be used to fuel a variety of vehicles, but market demand for the devices during a large oil shortfall is highly uncertain sors. Oil replacement by LPG is limited by the quantities of LPG that can be produced from new natural gas production. And mobile gasifiers probably will be limited by the inconvenience of using solid fuels.

Summary

The potential for reducing oil consumption through the fuel switching options considered here is summarized in table 16. If these options are implemented, the major remaining uses of oil would be for transportation and other mobile engines, petrochemical feedstocks, asphalt, lubricants, and specialized industrial processes. There would also be some oil use remaining for home heating in regions 1 and 2 and some industrial boilers. Replacing large additional quantities of oil, therefore, will require production of synthetic transportation fuels and chemical feedstocks from coal and biomass.

A critical assumption in this analysis, however, is that sufficient natural gas would be available to replace 1 MMB/D of oil. If this is not available, then space heating and hot water needs in most regions could rely more heavily on electricity, but oil consumption by industrial boilers would increase substantially above these estimates.

Table 16.—Summary of Potential Reduction in Oil Use Through Fuel Switching
(thousand B/D oil equivalent)

	Year				
Use	1986	1987	1988	1989	1990
Electric utilities	320	430	500	570	590
Residential/commercial space heat and hot water	165	435	765	950	975
Industrial boilers	190	370	510	605	655
Surface transportation	50	80	165	245	280
Total	725	1,315	1,940	2,370	2,500
Increased natural gas use[a]	440	740	960	1,000	1,020
Increased solid fuel use[b]	120	390	780	1,120	1,240

[a] Includes increased use of gas for incremental fertilizer production for the agriculture used to supply ethanol feedstocks.
[b] Includes fuel used in ethanol production and for increased electric generation, assuming that 80 percent of the increased electric generation is in coal-fired powerplants.

SOURCE: Office of Technology Assessment.

ENVIRONMENTAL IMPACTS

The major changes in fuel use due to fuel switching are a reduction in residual and distillate oil use and an increase in natural gas and coal consumption. Although there would be a small decrease in emissions as a result of the reduction in distillate fuel oil use and a corresponding increase in natural gas consumption, the major impacts are likely to be associated with the changes in residual fuel oil and solid fuel consumption.

The increased use of coal (up to 115 million tons/yr) will require that production be increased by up to 13 percent over 1982 production, with attendant problems such as acid mine drainage, subsidence, and other mining-related impacts. About 65 million tons/yr of coal would be used in utility and industrial boilers converted from oil. To avoid increases in sulfur and particulate emissions, these boilers would have to use low-sulfur coal and particulate control systems, for which supplies are adequate for the postulated scenarios. However, there probably would be an increase in NO_x emissions in some of these boilers; and to the extent that fuels with higher sulfur contents are used in converted boilers (without new scrubbers), SO_2 emissions would also increase.

An additional 35 million tons/yr of coal would be used in new and existing coal-fired utility boilers to replace (mostly distillate) fuel oil used in the residential and commercial sectors, which would also lead to an increase or at least a delay in the reduction (through retiring older boilers) of SO_2 and NO_x emissions.

The remaining 15 million tons/yr would be used in new ethanol distilleries. Distilleries with a capacity of greater than about 50 million gal/yr of ethanol supplied with a single boiler (greater than 250 MMBtu/hr) would be subject to Federal New Source Performance Standards; but there are currently no Federal regulations for smaller boilers. Furthermore, the Environmental Protection Agency regulations promised for 1986 for boilers rated at 50 MMBtu/hr and larger will not include regulations on SO_2 emissions; and it is unclear how stringent the other regulations will be. Consequently, it is likely that emissions from most of the ethanol distilleries will be determined primarily by State and local requirements for emissions controls, and many distilleries will locate where these requirements are least stringent. Furthermore, since the ethanol will be used to replace gasoline (rather than residual fuel oil, as in the case of boiler conversions above), even if low-sulfur coal is used, a net increase in SO_2 and NO_x emissions will occur.

Production of 5 billion gal/yr of ethanol (which is capable of reducing U.S. oil consumption by about 0.1 MMB/D) would require a 15-percent increase in grain production. This would probably lead to more than a 15-percent increase in soil erosion and the accompanying pesticide and fertilizer runoff, because much of the new cropland used for grain production is more erosive than average cropland.

The increased supplies of wood for fuel could be supplied as part of careful forest management programs without significant adverse environmental impacts. However, if the wood is harvested in a haphazard manner, damage to the forest and, eventually, forestland productivity could be substantial. Furthermore, burning wood without emissions controls (e.g., for home heating) would likely lead to significant local increases in particulate emissions, including higher levels of polynuclear aromatics (which are generally not a problem with either central electric power generation or natural gas or oil combustion); but sulfur emissions from wood are insignificant.

APPENDIX A—REASONS FOR EXCLUDING VARIOUS OIL REPLACEMENT TECHNOLOGIES FROM DETAILED CONSIDERATION

The initial list of fuel switching technologies (table 6) was screened to identify those options with the greatest potential for replacing at least 0.2 MMB/D of oil within a 5-year period following a large oil shortfall in 1985. Some of the technologies that were eliminated from further consideration by this screening process and the specific reasons for eliminating them are given below.

Fossil Synthetic Fuels

The primary concern of this study is to examine the technologies that can be deployed within 5 years after the onset of an oil shortfall. Construction of new, large-scale oil shale and coal liquids plants is likely to take longer than 5 years.[106] Although additional modules could be added to synfuel plants already in operation by 1985-90, in OTA's judgment the total additional output, beyond that already planned, is not likely to exceed 0.1 MMB/D before 1990. Consequently, large-scale oil shale and coal liquids plants are judged to be longer term options that are beyond the scope of this study.

True in situ oil shale retorts,[107] on the other hand, can be constructed in a matter of weeks. The retorts, which are underground cavities prepared with explosive charges, cover about an acre each and produce around 20,000 barrels of shale oil over a 6- to 8-month period. Achieving 20,000 B/D of production would require the completion of at least one retort per day, year round. This would entail a sharp increase in the number of trained personnel, construction of pipelines and new roads to remote areas, and considerable new equipment. (To date about 25 test retorts have been completed over a 7-year period.) The logistics of accomplishing this expansion, together with the remaining technical uncertainties in the process (notably the depth of overburden that can be accommodated and the control of fugitive emissions) would probably limit production to well below 0.1 MMB/D within a 5-year time period.

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[106] *Increased Automobile Fuel Efficiency and Synthetic Fuels*, op. cit.

[107] Ibid.

Another possibility is to use methanol produced from natural gas or to convert the methanol to gasoline. Currently, the United States has the capacity to produce methanol with an energy equivalent to about 50,000 B/D of oil (i.e., about 1.5 billion gal/yr of methanol). A fraction of this could be diverted to use in vehicles; and some new capacity could probably be built in 3 to 4 years, if the appropriate permits could be obtained quickly. However, the large capital investments needed, the dependence of these plants on uncertain future supplies of natural gas, the need to prove the methanol-to-gasoline step in commercial practice in this country, and (in the case of methanol) the uncertain demand for the product are all likely to limit rapid investment in these options. At best, one would expect potential investors in these technologies to wait until natural gas supplies and prices had stabilized somewhat, so that they could make reasonable estimates of the profitability of their investments.[108] This delay would probably mean that only very limited quantities of liquid fuels from natural gas would be produced within the 5-year timeframe, even if natural gas supplies eventually proved to be adequate. Furthermore, to the extent that surpluses of natural gas are available, more transportation fuel could be produced in the shortest time by using the natural gas to replace distillate fuels directly and converting them to diesel and gasoline.[109] Consequently, elimination of a detailed consideration of liquid fuels from natural gas is not likely to affect materially the results of this assessment or underestimate the oil replacement potential from fuel switching significantly.

Active Solar Systems

Currently there are about 500,000 active solar systems installed for heat and hot water, displacing the energy equivalent of 3,000 to 5,000 B/D of oil.[110] In 1982, about 150,000 systems were installed;[111] and at this rate of installation, active solar systems of this type could replace the energy equivalent of 5,000 to 8,000 B/D of oil by 1985. Even if this replacement could be increased by a factor of 10 between 1985 and 1990 (a highly optimistic estimate), it would still be less than the equivalent of 0.1 MMB/D of oil; and only part of the energy directly replaced would be oil. (Although the electricity and natural gas replaced by solar systems could be used to replace oil, the uncertainty in the future supplies of electricity and natural gas are far greater than any potential contribution from these sources.) Consequently, it is judged that the oil replacement potential of active solar systems between 1985 and 1990 is too small for a detailed consideration of this option.

Photovoltaics

Current photovoltaics production capacity is about 10 MW peak[112]/yr and could grow to 30 MW peak/yr by 1984. However, even if the production capacity were to grow to 500 MW peak/yr by 1990 and all of the photovoltaic devices sold were used to replace oil, the total replacement would be less than 10,000 B/D. Consequently, the oil replacement potential of this option is too small for detailed consideration.

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[108] It should be noted that potential investors in liquid synfuels from natural gas differ in three significant ways from those who may invest to convert facilities from oil to natural gas. First, the synfuel investor has the option not to invest without suffering a loss, while businesses may require fuel to stay in business. Second, the investment needed to convert from oil to natural gas is usually only a small part of a business' total investment, and the direct cost to the business (per unit oil replaced) of converting is usually considerably less than that of a synfuel project. Consequently, the risk is lower for the business converting than for a synfuel investor. Even if the investment proves to be unprofitable, it is not necessarily a mistake that would lead to bankruptcy for a company converting to natural gas, whereas it would be for a synfuel project. Third, a business could convert to natural gas while retaining the ability to convert quickly back to oil if natural gas supplies became too scarce. This option is not feasible for the synfuel producer.

[109] The quantity of transportation fuel that can be produced from a given amount of natural gas by displacing residual fuel oil, however, is closer to the amount that can be produced by converting the natural gas to liquid fuels, since the efficiency of converting gas to liquids is closer to that of upgrading residual fuel to diesel and gasoline, about 70 percent. Nevertheless, it would still take considerably longer to convert large quantities of natural gas to liquids than to replace and upgrade residual oil, since new natural gas liquefaction facilities would have to be built, whereas there would probably be excess residual upgrading capacity during a shortfall ("Emergency Preparedness for Interruption of Petroleum Imports into the United States," National Petroleum Council, April 1981).

[110] "The 1983 Renewable Energy Forum: Directions '90," Renewable Energy Institute, Conference Proceedings, Wye Plantation, MD, June 16-18, 1983; and Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase I," op. cit.

[111] "Renewable Energy Forum," op. cit.

[112] Peak power corresponds to the maximum power output when the photovoltaic cell is illuminated with the intensity and spectrum of light produced by the Sun at noon on a clear day.

Electricity From Wind

Wind-powered electric generators are being tested by electric utilities in several parts of the United States. The devices will have to be tested for several years, however, so that the utilities can determine exactly how the wind generators affect the utilities' total electric system (in terms of stability, reliability, fuels replaced, etc.). Until this testing is complete, it is unlikely that there would be any extensive investment in wind-powered generators. Therefore, their oil replacement potential is relatively small and is likely to remain so until at least 1990.

Solar Thermal Electric Generation

The use of solar thermal energy for electric generation is subject to constraints that are similar to those mentioned above for electricity from wind. Aside from Hawaii, the most favorable region for solar thermal electric generation is in the Southwest, a region where there is considerable generating capacity currently under construction. Unless demand for electricity in that region grows much more rapidly than OTA expects, electricity needs through 1990 could be met and the utility oil use replaced by completing the powerplants currently under construction, converting some utility boilers to coal, and using natural gas in the remaining oil boilers (almost all of which are equipped to burn oil or gas). Even without the coal conversions, all of the oil could be replaced by new powerplants and a modest increase (about 0.04 TCF) in gas use. Hawaiian utilities, however, would continue to use about 20,000 to 30,000 B/D of oil, but this amount of oil is too small for a detailed consideration of solar thermal electric generation.

Electric Vehicles

Except in special applications, the poor performance and low driving range of electric vehicles limit their market and make them most nearly a substitute for very high efficiency conventional cars.[113] In addition, electric vehicles are relatively expensive (compared to other options for displacing oil),[114] and it would take several years to convert automobile production facilities to produce large numbers of these vehicles. Consequently, the oil replacement potential of electric vehicles is relatively small within the timeframe considered for this assessment.

Ethanol From Food Processing Wastes

OTA's earlier assessment of "Energy From Biological Processes" included a survey of various agricultural and food processing wastes.[115] This survey indicated that even if all the largest sources of food processing wastes suitable for conversion to ethanol (cheese whey, tomato pumice, potato peel and pulp, and citrus rag and peel) were converted, the total amount of ethanol produced would be considerably less than the energy equivalent of 10,000 B/D of oil. Although these may be important energy resources in specific localities, their total oil replacement potential is too low for a more detailed consideration in this assessment.

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[113] *Increased Automobile Fuel Efficiency and Synthetic Fuels*, op. cit.

[114] Ibid.

[115] *Energy From Biological Processes*, op. cit.

APPENDIX B—ADDITION CONSIDERATIONS REGARDING ETHANOL'S NET ENERGY BALANCE

For average corn production, the oil (for cultivation, harvest, and grain drying) and natural gas (for fertilizers and pesticides) used to produce the corn have an energy content that is about 35 percent of the energy content of the resultant ethanol. For marginal cropland, which is less productive than average cropland, closer to 50 percent of the ethanol's energy content is consumed as oil and natural gas inputs to grain production.[116]

With large increases in corn production, shifts such as the following could also occur. Corn production could increase in Nebraska, at the expense of grain sorghum production. Production of grain sorghum could then increase in Texas. Assuming that marginal acreage is 70 percent as productive as the average in each State, the net result of this would be to increase agricultural consumption of oil and natural gas by 160 percent of the energy content of the resultant ethanol.[117]

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[116] Ibid.

Another aspect of ethanol's energy balance involves potential reductions in refinery energy use through blending ethanol as as octane-boosting additive to gasoline. These savings occur in some refineries by allowing the refiners to reduce the amount of reforming needed to upgrade the octane of their gasoline pool.[118]

While OTA's analysis indicates that gasoline production, as a percent of total refinery products, would be only slightly larger in 1990 than in 1985, diesel production would increase from 62 to 81 percent of middle distillate products (see ch. VI). The increased diesel production would require additional hydrogen to upgrade the middle distillate fraction. Since this hydrogen normally is produced from reforming a part of the middle distillates to high octane gasoline, the increased demand for diesel would encourage more reforming, thereby reducing the incentive to lower the octane of gasoline being produced. In addition, if the octane of the refinery's gasoline pool were reduced, the hydrogen not produced through reforming would have to be replaced with hydrogen from other sources, such as by reacting residual oil with steam. Although OTA has not conducted a detailed analysis of the effects of ethanol on refinery energy consumption following an oil supply shortfall, it seems likely that, under these circumstances, refinery energy savings from the use of ethanol would be greatly reduced. Clearly there would be exceptions to this general statement for individual refiners, but the average refinery savings associated with 5 billion gallons of ethanol production per year (corresponding to 10 percent ethanol in over half of the gasoline) are likely to be small.

Finally, if ethanol production were expanded much beyond about 2 billion gal/yr, the energy credit for not having to produce soybeans (about 10 percent of the energy content of the ethanol[119]) would begin to drop, since the soybean substitution market would begin to be saturated with the available distillers' dry grain.

The result of these changes in agricultural energy use and potential energy credits for ethanol production are as follows. If there were a surplus of natural gas, increased use of this fuel in agriculture would not compete with fuel switching from oil to natural gas in other sectors; and the natural gas usage should not be counted as a deficit in terms of oil replacement. In this case, each gallon of ethanol could provide a net oil replacement equal to 40 to 75 percent of the energy content of the ethanol. In other words, 5 billion gal/yr of ethanol could replace 0.08 to 0.15 MMB/D of oil.

On the other hand, if natural gas were in short supply, additional use of it in agriculture would compete with fuel switching to natural gas in other sectors; and the added agricultural use of this fuel would reduce the oil replacement in the other sectors. In this case, ethanol production could result in anything from a net replacement of oil equal to 50 percent of the energy content of the ethanol to a net **increase** in oil consumption equal to 60 percent of the ethanol's energy content. In other words, the effect of 5 billion gal/yr of ethanol production could vary from reducing oil consumption by 0.1 MMB/D to increasing it by 0.12 MMB/D.

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[117] Based on data from "Energy and U.S. Agriculture: 1974 Data Base," vol. II, U.S. Department of Agriculture, Federal Energy Administration.

[118] Note that the least sophisticated refineries, which simply distill crude oil into products, cannot achieve these savings because they do not do any reforming. But the use of ethanol by these refiners does increase the fraction of their product which can become gasoline of acceptable octane.

[119] *Energy From Biological Processes*, op. cit.

Chapter V

Increased Efficiency

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Chapter V

Increased Efficiency

INTRODUCTION

The potential for reducing energy use through increased efficiency—energy conservation—is one of the truly new public policy concerns of the past decade. Historically, the United States has simply shifted from one supply source to another as declining supplies or other concerns shifted consumer preference. Graphs showing U.S. energy use reflect similar steps from the use of wood to that of coal and then to oil. While basic engineering progress ensured the improvement of fuel efficiencies to some degree over time, the availability of low-cost, high-energy value fossil fuels in the country meant that there was little reward for using fuels in a frugal manner. Operating costs of U.S. energy-using systems —transportation, buildings, industry—were, in most cases, very small compared to the large first-costs of cars, homes, and plants. Accordingly, energy conservation commanded little research attention and no policy concern until after the 1973 embargo.

The rising prices and the specter of insufficient supply that followed 1973, however, set in motion a flurry of research, policy effort, and private commitment to pay attention to the cost of energy and to lower that cost through improved efficiency in design and process. Substantial research talent was allocated to find ways to meet energy end-use needs with less fuel. Early analysis indicated that there was in fact a substantial savings to be had at costs that were much lower than the likely costs for providing increased supply —in part because of the historical disinterest in the issue. This was the case, according to these analyses, in all sectors of the U.S. economy.

In addition to private investment and marketing efforts throughout the 1970s, the Federal Government approached conservation through all policy channels—subsidy, information transfer, and regulation. A wide variety of programs was authorized and funded.[1] State and local energy offices sprang up as well, and conservation was often a principal emphasis of these programs.

The rapid learning curve on conservation and its many positive characteristics made it popular with many policymakers. The positive characteristics of conservation include:

1. The ability to use a wide range of techniques to solve the site-specific efficiency problems.
2. Small scale and an emphasis on existing technology allowed for quick implementation.
3. Conservation options that were cheaper than many supply options to meet heating needs, and often do not require the large capitalization of a large-scale supply technology.
4. Excellent returns on investment in efficiency options through savings on future fuel cost increases (the higher fuel costs rise, the faster the return).
5. Potential for avoiding protracted conflicts over the siting of new supply facilities, such as power lines and generating plants, if requirement for new supply is reduced.
6. Benign environmental impacts compared to those from extractive fuel technologies, both at extraction and use points.
7. Possibility for local and individual decision-making and control.
8. Creation of jobs in manufacturing, installation, auditing, and related skills.

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[1] *Federal R&D Funding for Energy: Fiscal Years 1971-84*, National Science Foundation, Special Report, February 1983. "Energy conservation projects reflected the steepest gain of all energy R&D programs during the 1974-80 period, moving from $9 million to $264 million. The chief thrust was toward improved efficiency of energy use in transportation, especially automobiles. A substantial share of the effort was also aimed at buildings and community systems, and at industrial systems, to be cost-shared with industry. The present administration, in the belief that strong financial incentives exist within the economy to develop technically and economically promising technologies, has reduced conservation activities to a single program under the heading of energy conservation research; industrial, transportation, and buildings and community systems programs have been completely eliminated. Proposed R&D funding for energy conservation was $19 million in the 1983 budget. The average annual decrease of 58.5 percent for conservation support in the 1980-83 period was the greatest of any energy program."

While American energy use for all applications has been dramatically reduced (on a per capita or other appropriate basis), the portion of the reduction directly attributable to investments in improved efficiency is the source of some debate. Methods for measuring actual end-use behavior are not in place, and the isolation of a single variable is extremely difficult. For example, consider personal travel. The 1975 Energy Policy and Conservation Act set fuel economy standards for automobiles. Very substantial savings have resulted from these standards and a shift in market demand to smaller (more efficient) vehicles, and the savings will continue and increase as the stock of automobiles is turned over throughout the 1980s. An additional factor in gasoline use, however, is vehicle miles traveled. A large portion of gasoline savings between 1978 and 1980 appears to have resulted from a reduction in vehicle miles traveled. Similarly, energy use per unit output in industry has dropped, but it also appears that the market basket of products has altered to reflect a mix of products that are simply less energy-intensive.

Without doubt the most complex area of analysis on the impacts of conservation has been in energy use in buildings, and in particular in the residential sector. U.S. energy use per household is now strikingly below the levels predicted even in the mid-1970s. There is growing evidence, however, that most of this reduction is due to less use and not to more efficient homes. Changing patterns of household formation, shifting work schedules, and other factors are also important. All of these factors are strongly connected, however, and difficult to quantify separately.

In fact, one of the principal difficulties associated with conservation policy questions has been the issue of measurement. While it is quite simple to measure new supply—a fuel is either produced or it is not—the attribution of savings to specific actions is complex.

These measurement and attribution problems aside, however, the response to energy conservation opportunity stands as one of the striking aspects of energy use in 1983, as opposed to that in 1973. Energy conservation is now a criterion in many investment decisions. Problems of implementation now substantially outweigh problems in technology development, although there are still many technical unknowns. Readers interested in detailed analysis of the technical and implementation issues relating to conservation are encouraged to refer to the following OTA publications: *Residential Energy Conservation, The Energy Efficiency of Buildings in Cities, Industrial Energy Conservation,* and *Increased Automobile Fuel Efficiency and Synthetic Fuels: Alternatives for Reducing Oil Imports.*

BUILDINGS

Energy use in the residential and commercial sectors is largely determined by the stock of buildings. In 1980, the residential sector consisted of 80 million households, an amount expected to increase to 95 million units by 1990. In the commercial sector, there are about 4 million buildings, with a total floorspace of 44.7 billion square feet (ft^2). Total floorspace is expected to grow to 57.7 billion ft^2 by 1990.

In both sectors, natural gas is the major fuel used, primarily because it is relatively inexpensive, clean, and easy to handle. In 1980, residential gas use was equivalent in energy to 2.4 million barrels per day (MMB/D) of oil, or 52 percent of total sector energy use. The Energy Information Administration (EIA) projects that natural gas will remain the primary residential fuel through 1990, but its share will decline. By 1990 electricity is projected to replace natural gas as the primary fuel in the commercial sector.

Today, electricity use is second only to natural gas in both the residential and commercial sectors. Electricity is used primarily for nonheating purposes, for example, in air-conditioning, lighting, cooking, and refrigeration, etc. By 1990, EIA estimates that residential electricity use will increase to about one-third of all sector energy used, principally due to greater use of electricity for space heating. In the commercial sector, 1980 electricity use was equivalent to 1 MMB/D of oil, and EIA projects that this figure will increase to 1.4 MMB/D energy equivalent in 1990. This projected rise in commercial sector electricity use is largely due to an increase in office and retail/wholesale office floorspace, particularly in the South and West regions, which are heavily dependent on electricity.

About 14 million residential buildings use oil (including kerosene) for heating and hot water; consequently, the total oil used in the residential sector is relatively small. In 1980, 0.7 MMB/D of oil, or 15 percent of all energy, was used in residential buildings. EIA projects that oil consumption will decrease slightly, declining to a little over 0.6 MMB/D by 1990. On a regional basis, the highest percentage of heat from oil is found in New England, followed by the Mid-Atlantic region. EIA data show that the percentage of oil used for heat in homes is twice as high in urban as in rural areas. Most of these homes are under 2,000 ft^2 and were constructed before 1959.

Like the residential sector, the percentage of commercial buildings using heating oil is small—20 percent, or 762,000 buildings—and is concentrated in the Northeast. Moreover, the EIA projects that fuel oil use in the commercial sector will increase throughout the 1980s. In 1980, this sector consumed 0.6 MMB/D and is projected to consume 0.7 MMB/D by 1990. Projected growth in floorspace will offset the improvements in efficiency and conversion to other energy sources. By 1985, residential and commercial oil consumption is projected to be about 1.3 MMB/D with about half being consumed in each sector.

As stated previously, natural gas accounts for a much larger share of the buildings sector total than oil. Even though the natural gas share declined in 1982, it still provided almost half (48 percent) of total energy, while oil provided about 17 percent. Furthermore, as discussed in chapter III, oil consumption by residential and commercial users accounted for only about 8.3 percent of total U.S. oil consumption. Consequently, energy conservation in homes and commercial establishments will likely have a much greater impact on demand for natural gas than for oil.

Heating Oil Conservation

To estimate potential oil savings through investments in energy conservation in residential and commercial buildings, OTA first determined energy use by fuel for each sector separately from 1981 EIA State energy use data. These totals were aggregated into the 10 Department of Energy regions (see table 17). Next, OTA assumed that petroleum demand in these two sectors would be near the 1981 level when the hypothetical disruption occurs in 1985. This assumption means that oil demand rebounds from its 1983 low. Current EIA projections are in accord with this assumption.

In these two sectors, oil is used primarily for both space and water heating in buildings. About 80 to 85 percent is used for space heating, and the remainder for water heating. The calculations that follow concentrate on the space heating portion.

OTA will also carry out the calculation of oil conservation potential independently of the estimate for fuel switching which of course is going on at the same time. Initially, building owners will probably invest in either or both conservation and fuel switching when they see the price of oil escalate rapidly as supplies are suddenly reduced. Instead of making any assumptions about the separate contributions of the two types of investments, OTA calculated each alone, as if the other were not occurring, and then combined the two and eliminated the overlap. This last calculation is described in chapter VI.

Table 17.—Assumed 1985 Oil Consumption in the Residential and Commercial Sectors, by Region (thousand B/D)

	Residential	Commercial	Total
Region 1	133	50	183
Region 2	145	99	244
Region 3	129	43	172
Region 4	81	50	131
Region 5	151	54	205
Region 6	25	113	138
Region 7	47	16	63
Region 8	18	7	25
Region 9	11	51	62
Region 10	26	9	35
Total	766	492	1,259

SOURCE: Office of Technology Assessment.

Conservation in buildings can be achieved by a number of means that reduce the energy requirements of the building and its appliances, increase the efficiency of energy-using equipment, or some combination of each. For this analysis, OTA considered only those investments that would directly reduce heating oil requirements and that would have the greatest effect in the largest number of buildings. For residential buildings, analysis and post-retrofit data to date show that the combined effect of insulation in ceilings and walls and replacement of existing burner assemblies on oil furnaces with high-efficiency burners are the most cost-effective options for reducing oil use. The data indicate that oil use for space heating can be reduced by about 25 percent for an average unit.

In contrast, the potential for insulation to reduce oil consumption in commercial buildings is much more limited. For example, owners of large commercial buildings with clad walls and flat-roofed buildings with no cavity above the ceiling will find adding insulation to be a rather unattractive investment. Replacement of burners, however, will be quite cost effective, and will reduce oil use for heating about 20 to 25 percent on the average. There are other opportunities for commercial buildings such as conversion of terminal reheat forced-air systems to variable air volume systems and installation of stack heat reclaimers for heating systems that use water. Only the replacement of burners, however, offers cost-effective improvements in heating efficiency for all types of commercial buildings and heating systems.

The next step in determining potential oil savings is to estimate the number of buildings that can be retrofitted[2] during the 5-year period. In the residential sector OTA assumed that one-third, or 4.5 million homes, will be reached. This number is somewhat arbitrary and recognizes that many of the oil-burning homes in the country are not capable of being insulated or are already insulated to the levels OTA assumes. In the former category, there are many homes for which wall insulation is not feasible because there are no cavities in which to place insulation. In addition, a number of homes would require extensive repairs before insulation could be effective.

For commercial buildings, OTA assumed that all 762,000 buildings were reached. The much smaller number of buildings combined with the limitation on replacing burners in commercial buildings was the basis for this assumption. Again, the choice is somewhat arbitrary. As will be seen in the next chapter, about 80 percent of the oil used by all buildings is determined to be replaced by alternative energy sources. Therefore the amount of oil that is "replaced" by conservation is small, and errors introduced by an incorrect estimate of the number of buildings actually retrofitted with insulation and/or new oil burners

Photo credit: U.S. Department of Energy

Insulation material is blown into the wall cavity to increase the energy efficiency of this building

Table 18.—Potential Oil Replacement by Energy Efficiency Investments in the Residential and Commercial Sectors (thousand B/D)

DOE region	1985	1986	1987	1988	1989	1990
1	0	8	15	19	21	23
2	0	8	18	25	31	37
3	0	6	12	16	20	22
4	0	8	10	16	17	19
5	0	7	14	18	23	26
6	0	8	16	21	27	30
7	0	2	4	6	6	6
8	0	2	3	3	3	3
9	0	5	8	10	12	14
10	0	2	4	5	5	5
Total = 185,000 B/D						

SOURCE: Office of Technology Assessment; base consumption data Energy Information Administration.

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[2] Retrofit means to install additional or replacement equipment in an existing building.

will be even smaller, less than 10 percent of the oil used in 1985.

Using the above assumptions, OTA calculated the oil displacement schedule in buildings by region from 1985 through 1990. These figures are shown in table 18. The total oil displaced at the end of the 5 years by conservation is about 185,000 barrels per day or about 15 percent of the total used for space heating in 1985 by all buildings.

OTA estimates concerning the number of buildings that could be retrofitted over the 5 years were determined by limitations imposed by the physical state of the buildings themselves, because the principal source of conservation is the insulation of the building shell in the case of residential units. These estimates must now be compared with the constraints presented by the manufacturing capacity of insulation and replacement burners and by the personnel needed to audit these buildings and install the equipment. Because OTA dealt only with equipment and not with the physical condition of the structure, we did not need to go through this two-step process in that case. Personnel limitations, however, were factored in.

OTA first determined whether sufficient additional insulation could be made available during an oil disruption to meet the requirements calculated above. Assuming a floor area of 1,200 ft^2 and a wall area of 935 ft^2 for a typical house, R-30 insulation in the ceiling and R-11 in the walls, about 46,000 R-ft^2 of insulation[3] is needed per house, or a total of 216 billion R-ft^2 for all the residential buildings insulated over the 5 years. In 1977, estimates of annual production capacity for fiberglass insulation ranged from 100 billion to 160 billion R-ft^2. In addition, the industry expanded its production capacity in 1979 after the increase in oil prices. Therefore, no apparent constraints to meeting the insulation requirements for oil-heated homes at least, exist.[4]

Burner production capacity also appears to be sufficient. The number of replacement burners required is about 5.3 million over the 5 years. Current production capacity is about 1.5 million a year. Therefore, as long as the replacement is phased in over the entire period, there will be no shortage. It must be noted that the fuel switching calculation for buildings described in the previous chapter required over 8 million replacement burners to switch from oil to natural gas. This apparent constraint is not real, however, since only those oil users not converting to other fuels—less than 1 million—would actually need new oil burners. In other words, when conservation and fuel switching are combined, about 9 million new, high-efficiency burners are required in total. With a modest growth in production capacity (9 percent per year), this amount could be supplied in the 5-year period.

Perhaps the greatest constraint to achieving the oil savings target is the large amount of auditing and retrofitting which will be needed. This, in turn, will require a large increase in personnel over current activities. In recent years, there has been a decline in the number of private firms offering these services, however. Many have gone out of business or shifted their efforts to the commercial sector because of decline in demand for retrofits to residential buildings. Although a shortage of knowledgeable auditors may exist immediately after the disruption, a large number can be trained and on the job within a short period of time. The current industry standard for training auditors is about 6 to 8 weeks, including both specific training and some on-the-job, supervised time. Quality control, however, both in training auditors and product installations and performance, may be a serious problem.

To see whether audits and retrofits can be performed at the rate required to achieve the conservation targets, OTA examined the recent history of audit and retrofit programs. Under the Residential Conservation Service, mandated by the 1978 National Energy Conservation Policy Act, nearly 2 million audits were conducted by local electric or gas utilities from April 1981 to March 1983.[5] This figure does not include many of the audits conducted by two of the largest and most active utilities: the Tennessee Valley Authority (TVA) and the Bonneville Power Administration (BPA). Between 1977 and 1983, TVA and BPA conducted 750,000 and 209,000 audits, respectively. In addition, TVA weatherized 350,000 units during that period. A large number of audits were also completed by other utilities over the last 5 years. For example, Pacific Gas & Electric audited more than 350,000 homes and weatherized over 315,000 of them. Since 1981, the Mass Save program sponsored by 48 utilities in Massachusetts and Connecticut conducted 166,000 audits, and Pacific Power & Light conducted 66,000 audits and weatherized nearly 29,000 homes. Many others were probably retrofitted, too, but were not reported by the utility since they were done by private contractors or were done by the homeowners themselves. While a national total is not available, it appears from this sample that there will be sufficient personnel to perform the necessary audits and retrofits. This is especially likely if the retrofits are confined to installation of insulation and/or replacement burners.

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[3] R-ft^2 is a measure of the wall or ceiling area being insulated times the R value (insulation properties) of the insulating material.

[4] *Residential Energy Conservation* (Washington, DC: U.S. Congress, Office of Technology Assessment, OTA-E-92, July 1979), p. 283.

[5] Eric Hirst, *Evaluation of Utility Home Energy Audit (RCS) Programs*, Oak Ridge National Laboratory, February 1984, p. 3.

For commercial buildings the problems of having sufficient numbers of qualified personnel to perform the necessary audits and retrofits are probably lower since there has been much more interest in investing in commercial buildings than in residential buildings for greater efficiency. In fact, it is likely that the potential for lowering oil use by conservation in these buildings may be lower than the 25 percent OTA assumed because substantial changes have already been made. The error will not be large when fuel switching is accounted for, however, since the net contribution of conservation will be much lower than in the case of no fuel switching.

Natural Gas Conservation

Although OTA concentrated its analysis on oil, OTA expects that building owners who use natural gas will also undertake conservation efforts during the 5-year period. Because of the large volume of natural gas used by buildings, even a modest success in conservation will provide a large quantity of natural gas for use as a replacement for fuel oil. About 46 million households and 1.9 million commercial buildings use natural gas as a heating fuel. In 1981 about 4.9 trillion cubic feet (TCF) of natural gas was used to heat these buildings. An additional 2.6 TCF was used for other building energy services, primarily water heating and cooking. If 10 percent of the heating gas were conserved over the 5 years, nearly 0.5 TCF/yr would become available at the end of the 5 years, which would be about 25 percent of the total that OTA estimates will be used for fuel switching. The availability of that conserved natural gas can be very important in easing any pressures that may arise if domestic natural gas production were to drop rapidly by 1990.

Obtaining a 10-percent reduction in natural gas use, however, will require levels of insulation in residential buildings and replacement burners in commercial buildings that may stretch the production capacity limits of those two items. If the 25-percent reduction in heating fuel requirements per building that OTA assumed for the oil case can be achieved, about 18.6 million residential units will have to be insulated. This would amount to 845 billion R-ft^2 of insulation, which, when added to the requirements for oil, would exceed the upper end of the range of 1977 production capacity. The expansion in production capacity since 1977, however, coupled with the potential for expansion during the 5-year period (the leadtime for capacity expansion ranges from 12 to 36 months) and the production capacity for other types of insulation—e.g., cellulose, rockwool—should be sufficient to meet the combined demands of oil- and natural gas-heated homes. Problems may occur if there is also substantial demand for electrically heated homes, although those homes are usually better insulated than homes heated by oil or natural gas.

Supplying the other major conservation technology, replacement burners, should not present any problems if one assumes that they will be needed only for natural gas-heated commercial buildings. This is a plausible assumption since residential buildings can achieve the 25 percent savings with increased insulation alone, while insulation will be far less effective for commercial buildings, for reasons stated above. The type of burners that would improve the efficiency of natural gas-fired furnaces are somewhat different than those needed for oil-fired furnaces because the latter require atomization of the fuel, while the gas burners do not. The principles behind increasing combustion efficiency, however, are the same for both types—e.g., increasing flame turbulence and residence time—so there should not be any significant difference in manufacturing capability between the two. With this assumption, therefore, about 1.9 million replacement burners would be required, which would be added to the 9 million for increased efficiency and conversion to natural gas of oil-heated buildings. The sum, about 11 million, could be produced over 5 years if production capacity increased by about 19 percent per year, starting with a 1985 production capacity of 1.5 million units per year. This growth rate is high enough, however, that there will probably be some limitations due to burner availability, although manufacturing is sufficiently simple that this growth rate could be achieved. The result of the burner production limitation would be to reduce the amount of natural gas available by conservation. Given that case, conservation in other uses of natural gas—cooking and water heating—would have to make up any differences that may be needed. The large amount used in those catagories, combined with many opportunities to increase efficiency there, makes it reasonable that such gas can be made available.

TRANSPORTATION

In 1980, the transportation sector consumed about 9.6 MMB/D of oil (see table 19). The main fuels consumed were gasoline (6.5 MMB/D oil equivalent), primarily for automobiles (4.6 MMB/D) and trucks (1.7 MMB/D), diesel (1.4 MMB/D), jet fuel (1 MMB/D), and residual fuel oil (0.7 MMB/D). In addition, OTA estimates that about 0.5 MMB/D were consumed by the industrial sector in off-road construction, mining, and agricultural machinery and equipment.

Consumption of gasoline, the dominant transportation fuel, peaked in 1978 at 7.4 MMB/D (including 0.1 MMB/D for nontransportation purposes). By 1979 it had dropped to 7.0 MMB/D and in 1980 it was 6.6 MMB/D. In OTA's judgment, only about half of this drop can be attributed to the increased efficiency of vehicles on the road; the other half must be due to a reduction in the vehicle miles of travel (VMT). Between 1980 and 1983, gasoline consumption has remained nearly constant because the continued increase in fuel efficiency has apparently been offset by increases in VMT. By 1983, VMT had returned to its 1978 level; and unless it continues to rise, gasoline consumption is likely to drop to around 6 MMB/D by 1985.[6] Consumption of other transportation fuels in 1985, on the other hand, is likely to be similar to its 1980 level.

All but about 0.1 MMB/D of the diesel and residual oil used in the transportation sector is for freight transports. OTA has not assessed potential fuel savings in freight transports, but a recent Argonne study indicated that fuel consumption could be reduced by 4 to 8 percent in an oil shortfall, starting in mid-1981 and similar in magnitude to the one postulated in this study.[7] The savings could be achieved through a variety of measures, including shifts in the mode of transportation (from air to truck, truck to rail, and rail to marine), changes in operating practices (e.g., less idling, compliance with speed limits, fewer empty runs, improved maintenance), and technical changes (e.g., different types of air filters, lubricants, tires; aerodynamic devices; temperature-controlled fans). Although some of these changes will have been implemented by 1985, the timeframe considered here (5 years) is longer than that considered in the Argonne study (1 year). Moreover, some older vehicles can be replaced with newer, more efficient models. The savings from fleet turnover, however, is likely to be considerably less than for passenger cars because transport

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[6] This assumes that the average fuel efficiency of new cars sold in 1985 will be 27.5 miles per gallon (mpg) and that the percentage efficiency increase in light trucks on the road will be half as large as that for automobiles.

[7] L. R. Johnson, et al., "Energy Contingency Planning for Freight Transportation," Argonne National Laboratory, ANL/CNSV-34, August 1982.

Table 19.—Transportation Oil Use by Mode and Fuel Type, 1980

	Fuel consumption (MMB/D)			
	Gasoline	Distillate fuel oil	Jet fuel	Residual fuel oil
Highway use	6.3	0.9	—	—
Motorcycles and mopeds	0.02	—	—	—
Automobiles	4.6	0.03	—	—
Buses	0.03	0.04	—	—
Trucks	1.7	0.9	—	—
Nonhighway use	0.15	0.4	0.8	0.7
Air	0.03	—	0.8	—
Water	0.1	0.08	—	0.7
Rail	—	0.3	—	0.002
Snowmobiles	0.01	—	—	—
Military operations	0.01	0.07	0.2	—
Total	6.5	1.4	1.0	0.7

SOURCE: Adapted from G. Kulp and M.C. Holcomb, "Transportation Energy Data Book, Sixth Edition," Oak Ridge National Laboratory, ORNL-5883, 1982.

vehicles are kept longer than cars[8] and the difference in efficiency between new transport vehicles and the average transport vehicle already on the road is less than for cars. Consequently, savings of the magnitude of 4 to 8 percent are probably still reasonable.

Although the engines in off-road vehicles and equipment used in construction, mining, and agriculture (CMA) are similar in many respects to those used for some types of freight transport, many of the adjustments (e.g., shifts in transportation mode) are not available to users of industrial engines. Consequently, the percentage of savings from increased efficiency in CMA machines and equipment is likely to be considerably smaller than that in freight transport; and OTA has not included any savings in the area of CMA machines and equipment.

Passenger aircraft consume about 75 percent of all jet fuel and over 98 percent of the jet fuel consumed by nonmilitary aircraft. Reductions in fuel consumption by passenger planes can be achieved by reducing the weight of interior equipment (e.g., seats, shelves), operating planes with fewer empty seats, removing exterior paint to reduce aerodynamic resistance, and other changes. Also, some planes will be replaced by newer, more efficient models. Again OTA has not assessed potential fuel savings in passenger planes, but if their fuel consumption could be reduced by 5 to 10 percent, the total savings in freight transport and passenger aircraft would be about 0.1 to 0.2 MMB/D.

Considerably larger savings are likely in passenger cars and light trucks.[9] Because the auto industry has been changing production facilities to produce more efficient cars and light trucks for a number of years, fuel consumption will drop between 1985 and 1990, with or without an oil disruption.

To illustrate the probable magnitude of the fuel savings, OTA has calculated three scenarios for automobile fuel consumption, shown in figure 35. In each case, it was assumed that the VMT are proportional to the number of automobiles on the road (i.e., average miles per vehicle is constant, as has roughly been the case historically).[10] It was also assumed that the average fuel efficiency of new cars sold in 1985 will be 27.5 mpg.[11]

In the base scenario (A) OTA assumed that the number of automobiles will increase by 5 percent between 1985 and 1990, that new car sales will average 11 million vehicles annually, and that the new car fuel efficiency in 1990 will be 27.5 mpg. For the disruption scenarios (B and C), OTA

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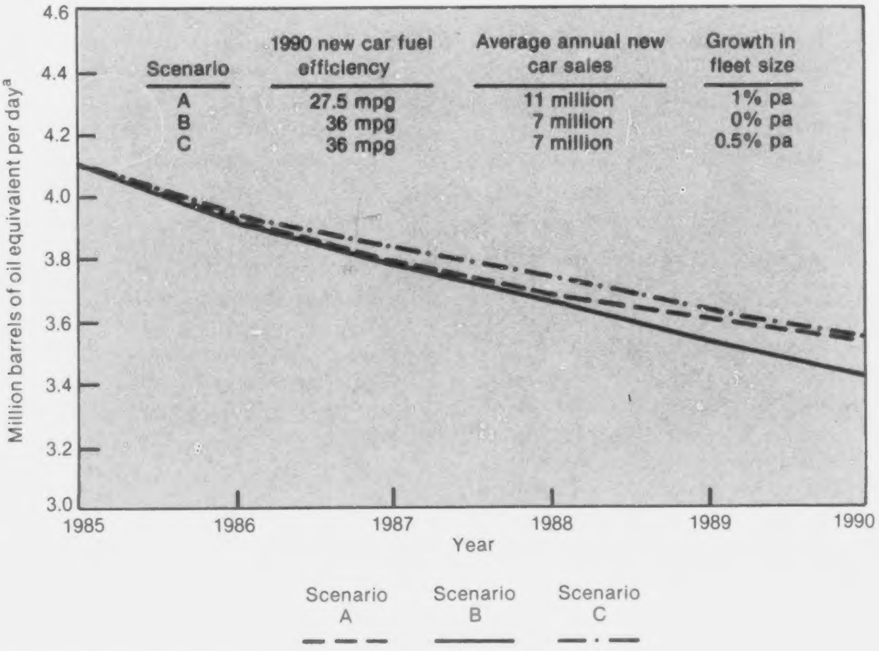
[8] G. Kulp and M. C. Holcomb, "Transportation Energy Data Book, Sixth Edition," Oak Ridge National Laboratory, ORNL-5883, 1982.

[9] *Increased Automobile Fuel Efficiency and Synthetic Fuels: Alternatives for Reducing Oil Imports* (Washington, DC: U.S. Congress, Office of Technology Assessment, OTA-E-185, September 1982).

[10] Kulp and Holcomb, op. cit.

[11] EPA composite fuel efficiency, consisting of 55 percent city and 45 percent highway driving cycles. Actual on-the-road fuel efficiency is assumed to be 10 percent lower than this.

Figure 35.—Automobile Fuel Consumption Projections, 1985-90



[a]At 5.5 million Btu per barrel of oil.

SOURCE: Office of Technology Assessment.

assumed that annual new car sales are depressed, averaging 7 million vehicles, and that the new car fuel efficiency in 1990 is 36 mpg, reflecting a market demand for more efficient vehicles. In scenario B, the automobile fleet size remains constant, while in scenario C, it grows by 2.5 percent between 1985 and 1990.

As can be seen in figure 35, the fuel savings in each of the scenarios are quite similar, about 0.6 to 0.7 MMB/D. These results show that the effects of opposing factors influencing fuel consumption more or less cancel one another. In the base case scenario, vehicle travel increases and demand for fuel efficiency is low. But new car sales are high, so many older, less efficient cars are replaced. In the disruption scenarios, new car sales are depressed; but travel increases less rapidly, and those cars that are sold are more efficient than in the base case.

One could postulate other scenarios, in which high sales and demand for fuel efficiency are coupled with low or no growth in travel; and the fuel savings could be increased to about 1 MMB/D. Or one could combine low sales and no increase in new car fuel efficiency with increased travel, in which case the savings could drop to about 0.4 MMB/D. In OTA's judgment, however, the scenarios shown in figure 35 represent the most plausible combinations of circumstances.

If one assumes that the percentage increase in the efficiency of light trucks is half that of automobiles, due to the slower turnover of the fleet,[12] then fuel consumption by light trucks would drop by about 0.1 MMB/D under circumstances similar to those postulated for automobiles. Total savings from increased efficiency of automobiles and light trucks between 1985 and 1990 would then be about 0.7 to 0.8 MMB/D, and the total reduction in fuel demand for transportation would be 0.8 to 1 MMB/D.[13]

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[12] Kulp and Holcomb, op. cit.

[13] This magnitude of fuel savings is consistent with a relatively constant demand for transportation services. A reduction or change in demand could also have a large effect, however. For example, if demand for transportation services drops by 10 percent across the board, fuel consumption would drop by an additional 0.9 MMB/D; and if 10 percent of the passenger-miles traveled by car shifts to buses, the savings would be around 0.2 MMB/D.

INDUSTRY

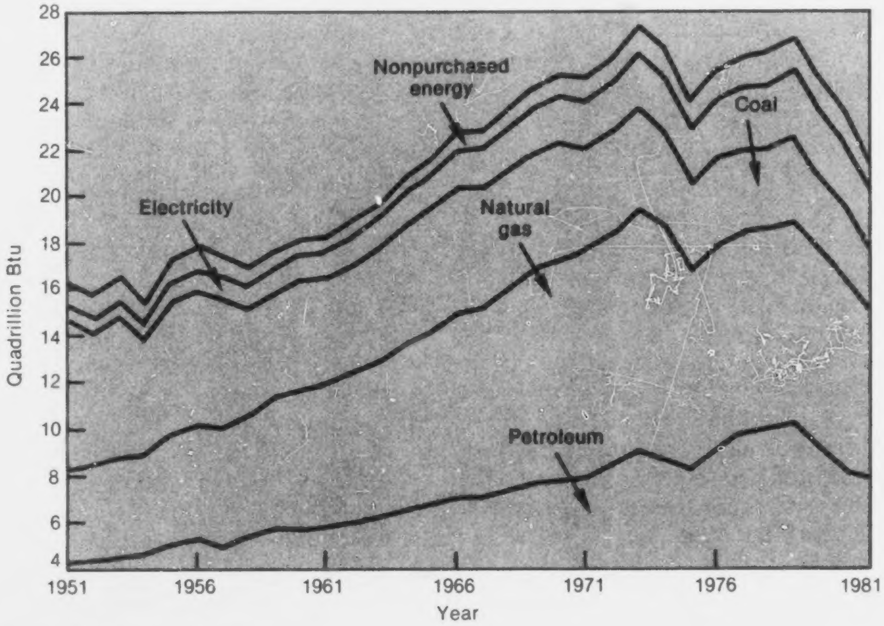
Since 1951, industrial use of energy in the United States grew from 17.4 quadrillion Btu per year (quads/yr), to almost 27 quads/yr by 1979. Since then, it has decreased rapidly to just over 21 quads/yr in 1983, although there are indications that industrial energy use is beginning to grow again.

In figure 36, the growth in industrial energy use reflects increases in the use of natural gas and petroleum fuels, and a decrease in the use of coal. The latter occurred because of the economic advantage of oil and gas compared to coal, including the environmental restrictions imposed on coal use in the 1970s. In 1950, coal was the largest source of industrial fuel, accounting for almost 40 percent of the energy used. Petroleum and natural gas accounted for approximately 25 percent each. By 1978, these shares had changed dramatically; coal accounted for only 12 percent of total industrial fuel, while petroleum had increased to nearly 40 percent. In terms of growth rates, total industrial energy use has grown at a rate of 1.7 percent per year between 1951 and 1979, and use of petroleum has grown at a rate of 3.5 percent per year. Coal use decreased at 2.7 percent per year. The absolute amount of petroleum used by industry rose from 1.96 MMB/D in 1951 to a high of 5.14 MMB/D in 1979.

It is apparent that 1978-79 was a watershed for energy use in American industry. Total final demand for energy fell from a 1979 high of 26.8 quads/yr (counting electricity at 3,412 Btu per kilowatthour [kWh]) to a 1982 level of 21.2 quads/yr. Oil fell from a 5.1 MMB/D industrial consumption level in 1979 to a 1982 level of 4.0 MMB/D. During this period petroleum's share of total energy use stayed approximately constant at 37 percent.

Table 20 lists the 10 most petroleum-intensive industries, as reported in the Department of Energy's 1980 *Industrial Energy Efficiency Improvement* annual report. These figures do not include petroleum basic feedstocks. The great-

Figure 36.—Industrial Energy Demand, 1951-81



SOURCE: Energy Information Administration.

Table 20.—Industrial Users of Residual Oil for Fuel—1980

Industry	Petroleum use (thousand B/D)
1. Paper and allied products	169
2. Petroleum and coal products	133
3. Chemicals and allied products	99
4. Primary metals	72
5. Food and kindred products	34
6. Stone, clay and glass products	22
7. Transportation equipment	17
8. Textile mill products	9
9. Rubber and miscellaneous plastics	7
10. Machinery, except electrical	6

SOURCE: *Industrial Energy Efficiency Improvement Program: Annual Report to the Congress and the President 1980*, Department of Energy, Office of Industrial Programs, Washington, DC.

est quantity of petroleum was consumed by the paper and allied products industry (SIC[14] 26), even though this industry was about 50 percent self-sufficient through the use of biomass as fuel. Note also that the top four petroleum-consuming industries account for over 80 percent of all residual fuel oil used in industry. This means that if petroleum use is to be curtailed or made more efficient, these four industries must play a large part.

OTA has made projections of the trends in fuel use which should occur by the year 2000, given a set of fuel prices that increase modestly but progressively over that time span. These projections were reported on extensively in OTA's report on *Industrial Energy Use*.[15] OTA projected that total industrial fuel use will increase above current levels, but at a rate much lower than the rate of growth of industrial output. The share of petroleum-based fuel is projected to decline from its current level of 37 percent of all industrial fuel to less than 30 percent by the year 2000.

Technologies Available to Reduce Oil Dependence

A number of technologies are now available whose widespread implementation could extensively reduce oil use by U.S. industry. Those technologies can be broken down into two broad areas: general technologies, such as those for heat recovery which are applicable to many industries; and specific technologies for particular industries.

General technologies include the following:

1. **Housekeeping** covers those things industry can do to improve the efficiency of energy use with a minimum of monetary investment. Items included would be routine maintenance of steam lines to prevent loss of steam through inoperative traps, switching off equipment not needed, and adjusting heat, ventilation, and air-conditioning systems for optimum performance at minimum cost.

2. **Computer control systems** either are added to improve the performance of an existing boiler system used to raise steam, or added to an industrial process to monitor a production line to see that feedstock material is not wasted and to ensure product quality. Addition of computer control systems to boilers allows the close monitoring of air and fuel so that unneeded air is not heated and unneeded fuel is not burned. In a production line, a computerized process control system can be used to optimize such things as paper thickness, polymer color, or petroleum viscosity. A number of parameters can be monitored simultaneously.

3. **Waste heat recovery** systems are available to improve the overall efficiency of energy use by recovering heat from combustion gases in a steam boiler or by recovering excess thermal energy from a process stream product. For example, when petroleum is first distilled, large quantities of energy are used to fractionate crude oil into different boiling-range components. However, the resulting distillates may not need to be so warm. Therefore, a heat exchanger can be built into the process stream to allow crude oil feedstock to absorb some of the thermal energy from the distillate before being introduced to the distillation unit, resulting in less energy being needed to fractionate the feedstock.

Another approach to heat recovery involves upgrading thermal energy to a level which can be useful as a heat source. A large amount of industrial energy is lost from process streams at temperatures less than 300° Celsius. To use such energy, vapor-recompression or heat pumps are needed to raise this low temperature heat to a more useful temperature and pressure. In terms of Btu, low-level heat has enormous potential to improve industrial energy efficiency.

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[14] SIC means Standard Industrial Classification of the U.S. Department of Commerce.

[15] *Industrial Energy Use* (Washington, DC: U.S. Congress, Office of Technology Assessment, OTA-E-198, June 1982).

Many industries have energy conservation technologies available to them that are unique to that industry. Below are some categories of technologies available to four of the most energy-intensive industries.

1. **The Chemicals and Allied Products Industry.** Technologies available for reducing petroleum dependence in the chemicals industry exist in two broad areas. The first involves improvements in physical separation technology, specifically the modification and possible elimination of distillation as a chemical separation technique. Incremental improvements in the distillation process, retrofitted to existing installations, already have achieved significant (e.g., 25 percent) savings in many plants. Further improvements of comparable magnitude could be made.

Alternative approaches to liquid separation are on the horizon, and could be implemented if distillation costs were high enough. These techniques include freeze crystallization separation, vacuum distillation, and liquid-liquid (solvent) extraction. The latter is a most promising technique, entailing the use of a solvent with a high affinity for one component of a chemical mixture, but immiscible with the remaining components. Using this technique, separation involves two steps: decanting and closed-loop evaporation/condensation of the solvent. One company has already used the technique in a synthetic fiber plant, saving an estimated 40,000 barrels of oil equivalent annually.

Production integration technologies also are available for improving petroleum use efficiency in the chemicals industry. Perhaps the simplest example is cogeneration of steam and electricity.[16] However, many other opportunities exist, notably in integrating chemical production into petroleum refining complexes. Also, integration of the production of ethylene, propylene, and a wide range of petrochemicals from a naphtha-based (aromatics-based) scheme is a strong possibility by 1990. Another option would be to integrate ethylene and acetylene production with ammonia and/or methanol. Ethylene/acetylene coproduction will become increasingly attractive as distillate prices rise and heavier feedstocks are used.

2. **The Petroleum Refining Industry.** The petroleum refining industry uses about 10 percent of its crude oil throughput as fuel for the various refining processes such as distillation and cracking. Since one of the assumptions of this study is that there is a sustained shortfall of 2.2 MMB/D in crude oil (an additional 800,000 B/D of imported petroleum products, mostly residual fuel oil, are also lost), it follows that the refining industry would use about 200,000 B/D less as fuel. This is probably conservative, since undoubtedly the most inefficient refining operations would be the ones shut down in a curtailment.

In addition to the lowered throughput, many of the technologies applicable to Chemicals and Allied Products can also be used in petroleum refining. And given the large amounts of low-level heat produced by refineries, there is the possibility of both thermal and mechanical recovery of heat using either new designs for production units or heat pumps.

3. **The Paper and Allied Products Industry.** The paper industry is now over 50-percent energy self-sufficient through using wood residue and spent paper pulping liquor as production fuel. One of the most efficient means of improving energy use in the industry would be to retire older equipment. The paper industry is unique in that much of its equipment is very long-lived, some as much as 50 years. New technologies available to the industry include continuous digesters for pulp production, cogeneration of steam and electricity or steam and mechanical drive, and new papermaking processes that reduce the amount of water that must be removed in drying.

4. **The Iron and Steel Industry.** Efficiency improvements in the iron and steel industry will involve simultaneous phasing out of older ineffi-

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[16] Cogeneration is the simultaneous production of both electrical or mechanical power and thermal energy from a single energy source. A detailed discussion of promising cogeneration technologies can be found in *Industrial and Commercial Cogeneration* (Washington, DC: U.S. Congress, Office of Technology Assessment, OTA-E-192, February 1983).

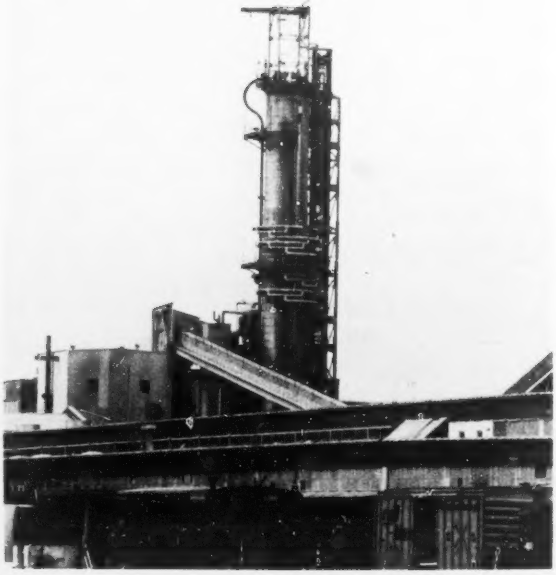


Photo credit: International Paper Co.

Paper and pulp are made from wood chips in an energy-efficient continuous digester

cient plants and equipment and the widespread introduction of the new technologies of electric arc furnace (EAF), minimills that recycle large amounts of scrap steel, and continuous casting (CC), which eliminates the cooling-reheat cycle for making intermediate steel products such as blooms and billets. The recent worldwide recession and resulting manufacturing overcapacity is forcing steel manufacturing firms to eliminate open hearth furnace operations in favor of EAF and CC technologies. However, while these new technologies will make steelmaking more efficient, they will not have a dramatic impact on petroleum use since only 7 percent of the energy used for steelmaking is petroleum.

Energy Conservation Potential of Industry

Industry has the potential to replace about 25 percent of its 1985 level of fuel oil consumption through increased efficiency and process changes over a 5-year period after the onset of an oil shortfall, while maintaining production levels. The analysis underlying this projection, much of which was carried out in support of OTA's recently published *Industrial Energy Use* report, is based on an engineering and economic computer model called "ISTUM," the Industrial Sector Technology Use Model which OTA used to examine the four most energy-intensive industries in U.S. manufacturing. For these industries, potential oil and natural gas savings were calculated for investments that would minimize total energy use per unit of production.

In the OTA report, oil and gas prices were postulated to increase an average of 3.5 percent per year between 1980 and 2000, while coal and electricity prices remained relatively constant. Product output for the entire industrial sector was assumed to grow at a rate of 2.9 percent per year. Energy use was then calculated to grow at one-third of this rate—i.e., 1 percent per year.

In the case of an oil supply shortfall, many anomalies would occur. Oil prices would quickly and dramatically increase, and industrial output would likely decline as overall demand for industrial products declined. In addition, the decline in crude oil supplies would result in a drop in refining throughput. The effect of these anomalies on oil consumption has been approximated through the following assumptions:

- Increased prices of oil fuels would accelerate investment in energy conservation projects by manufacturing firms if they choose to remain in production. This analysis assumes that energy-efficiency improvements that took place over 10 years in the original OTA projection (1985-95) would be achieved in 5 years—i.e., by 1990.
- Output from the major oil-consuming industries (except refining) will remain flat on the average for this 5-year period.
- Opportunities for the improvement of petroleum fuel use efficiency will be roughly comparable to that of the pre-disruption case. Even though OTA assumed that production output is not increasing, a certain amount of capital stock will still be replaced. To the extent that new equipment is used, it will be more energy efficient than the old equipment. Therefore, energy consumption per unit of output will decline over the 1985-90 time span.

- Refinery throughput will have decreased by about 2.2 MMB/D after 5 years, with an additional 800,000 B/D decline in imported residual oil.

By removing economic growth from the previous OTA results derived from ISTUM (for 1985 to 1995) and compressing those results from 10 to 5 years, we can account for the first two assumptions. We find, in this case, that about 250,000 B/D of distillate and residual fuel oil and liquefied petroleum gas (LPG) can be replaced between 1985 and 1990. In addition, the decline in crude oil throughput accounts for an additional 200,000 B/D, or a 0.4-quad decline in fuel use. The total of the two factors—conservation and lowered refinery through-put—is about 450,000 B/D, of which about one-third draws from the same pool of oil as was considered for fuel switching in the previous chapter.

In addition to oil savings, these conservation measures will also reduce natural gas use. Natural gas freed in this way can be used to replace oil requirements in industry and buildings not eliminated by conservation. Table 21 shows the projections of industrial energy conservation that can be achieved with each fuel over the 5-year period.

The final line in table 21 shows the conservation potential which is available in the event of an oil disruption. These figures show that 1.3 quads of natural gas could be saved, along with a total of 0.34 quad of petroleum-based boiler fuels. Under this scenario, coal, residual oil, and natural gas use was adjusted to eliminate fuel switching that was incorporated in the original ISTUM analysis. In addition, a correction was applied to the petroleum refining industry, to account for a decrease in conservation opportunities that would accompany a decrease in refinery throughput in that industry.

Projections of energy use for the four most energy-intensive industries were made for each technology within each industry, and these were totaled to project overall energy use by fuel within each of these industries. These projections were based on ISTUM modeling that analyzed energy use by dividing energy use into various energy service categories, a number of which are generic to all industries, while others are specific to a particular industry. Among the former are such categories as fuel for boiler-generated steam or fuel for heating, ventilation, and air-conditioning. Among the latter—specific to an industry—are those fuels for pulping of wood in the paper industry and crude oil distillation in petroleum refining. The numbers determined this way were then subjected to the same manipulation as described above for the energy of the total industrial sector—i.e., 10-year conservation measures are expected to be accomplished in 5, and there will be zero growth in each industry. In addition, petroleum refining industry fuel use has been cut by 200,000 B/D owing to decreased crude oil throughput.

In figures 37 through 39, OTA presents projections of the changes that are anticipated to occur in petroleum-based energy use, natural gas-based energy use, and total energy use within each of the four key energy-intensive industries. In the case of petroleum fuel use (fig. 38), the paper industry is projected to decline from a 1985 level of 130,000 B/D to a 1990 level of 86,500

Table 21.—Fuel Use Projections (in quadrillion Btu)

	Natural gas	Residual oil	Distillate oil	Total residual and distillate oil	LPG	Coal
1985 use	6.94	0.98	0.33	1.31	0.46	1.70
1990 use	4.51	0.78	0.18	0.96	0.29	2.83
1985-90 change	+2.43	-0.20	+0.15	+0.34	+0.16	—
Adjustment for fuel switching	+1.13	—	—	—	—	+1.13
Final fuel use conservation potential	+1.30	+0.20	+0.15	+0.34	+0.16	0.00

SOURCE: Office of Technology Assessment.

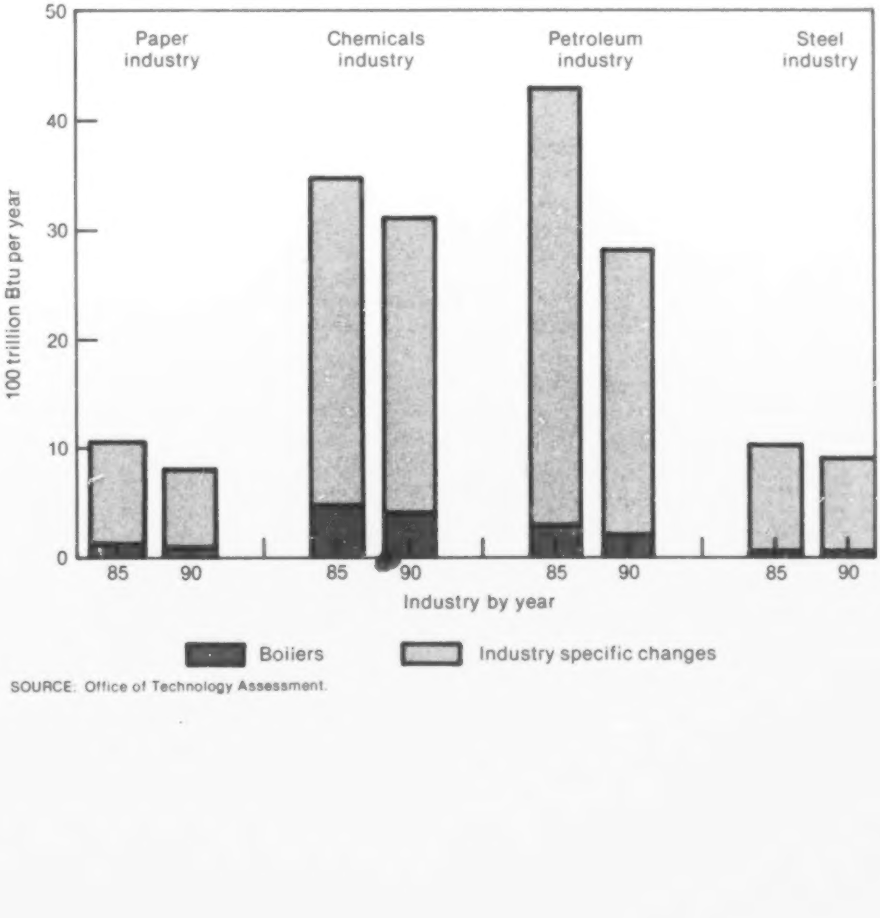
B/D, most of which will be used to raise steam. Much of that oil will be replaced by biomass fuels derived from wood feedstock. The chemicals industry is projected to reduce its petroleum fuel use by about 50,000 B/D over the 5 years, owing primarily to technological changes in the industry-specific categories.

In steel manufacturing, petroleum fuel use is projected to decline from 91,000 B/D in 1985 to less than 80,000 B/D in 1990, again reflecting technological change—i.e., to the penetration of EAFs.

Summary

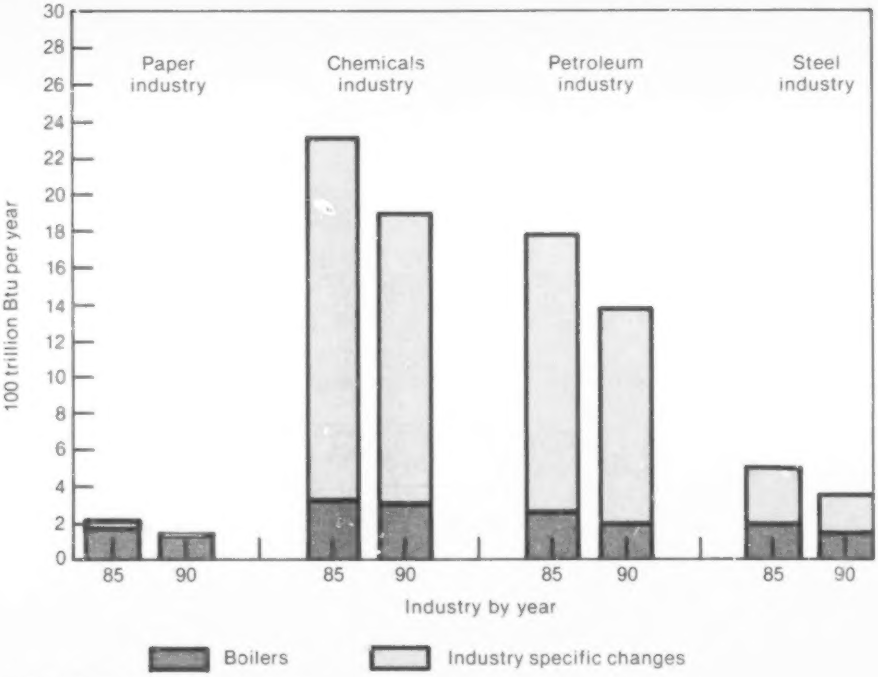
In summary, OTA has projected that U.S. industry is capable of a 250,000 B/D reduction in petroleum-based fuels in the 5-year period between a 1985 disruption and 1990, plus an additional drop of 200,000 B/D due to reduced refinery throughput. In addition, increased efficiency of natural gas use could save 1.3 TCF/yr of natural gas (equivalent in energy to 650,000 B/D of oil) in the same 5-year period.

Figure 37.—Total Fuel Use Projection (energy for four industries)



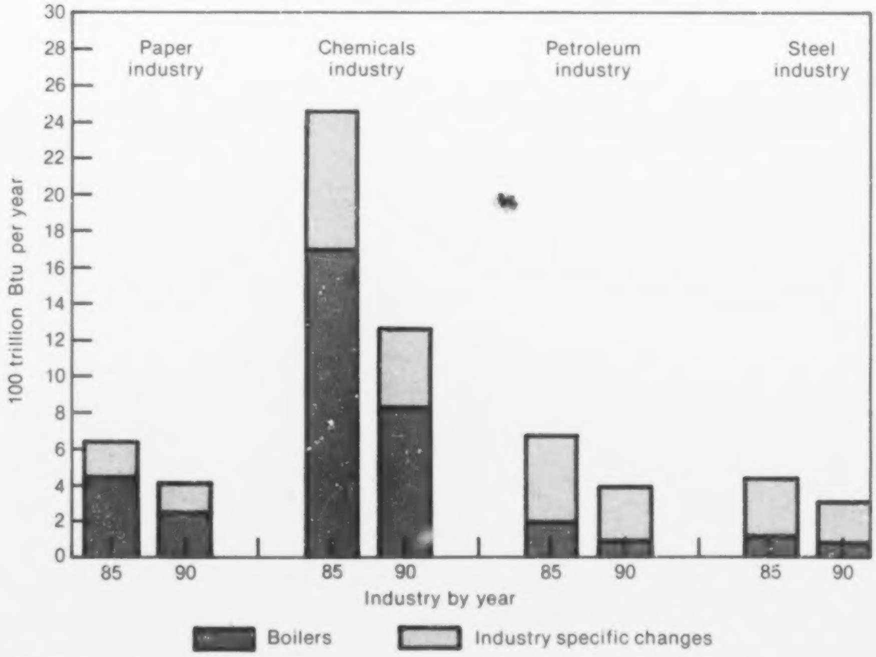
SOURCE: Office of Technology Assessment.

Figure 38.—Petroleum Fuel Use Projections (consumption by four major industries)



SOURCE: Office of Technology Assessment.

Figure 39.—Natural Gas Use Projections (consumption by four major industries)



SOURCE: Office of Technology Assessment.

Chapter VI

Fuel Use Changes and Longer Term Effects

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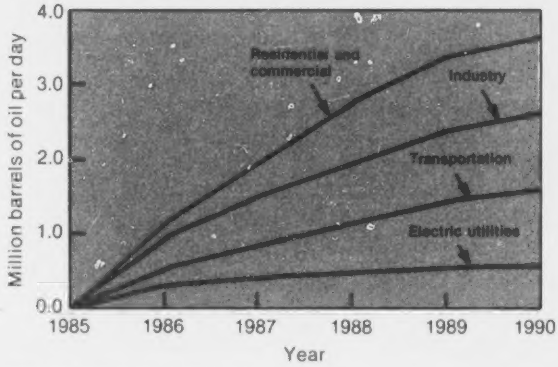
Chapter VI

Fuel Use Changes and Longer Term Effects

The individual contributions to reducing U.S. oil consumption through fuel switching and increased efficiency of use have been considered elsewhere in this report. In this chapter, the contributions are combined to provide estimates of the overall rate at which oil consumption could be reduced in a crisis. The corresponding changes in the consumption of various fuels are also described, possible alternative scenarios are considered, and the longer term implications of the shifts are discussed.

FUEL USE CHANGES

Figure 40.—Potential Replacement of Oil Through Fuel Switching and Increased Efficiency



SOURCE: Office of Technology Assessment.

To estimate the total amount of oil that can technically be displaced through fuel switching and increased efficiency, it is necessary to eliminate any double-counting (i.e., the overlap when the same oil can be displaced by both options), such as when a residence is insulated and converted from oil to natural gas. In gasoline- and diesel-fueled vehicles, there is only a small overlap because the potential for fuel switching (4 percent of fuel use) is small. In the industrial sector, the overlap is only moderate because about two-thirds of the oil that is replaced by increased efficiency and saved by reduced refinery throughputs is not used in boilers which are the targets for fuel switching. In the residential and commercial sectors, however, the overlap is much larger because both contributions are significant, and fuel switching can essentially eliminate oil use in these sectors in many regions of the country.

Figure 40 shows the composite oil replacement, with double-counting eliminated,[1] in each of the sectors considered and based on the scenarios derived elsewhere in the report. In electric utilities, fuel switching dominates the changes,[2] while in transporation increased automobile fuel efficiency dominates. In the industrial sector, increased efficiency can replace about one-fifth as much oil as fuel switching. In the residential and commercial sectors, about 15 percent of all the oil used in these sectors in 1985 can be replaced by 1990 through increased efficiency alone, while 77 percent of the oil used in 1985 can be replaced through fuel switching and increased efficiency combined.

In all, over 90 percent of the oil used in utility boilers and over 70 percent of that used in industrial boilers could be replaced by 1990. Other industrial uses of oil could also be reduced significantly. Oil used for transportation could be reduced by about 11 percent, mostly through reduced gasoline consumption. And in most regions of the country, residential and commercial oil use could be nearly eliminated. However, in New England and the New York/New Jersey region, only about 50 percent of the oil use could be replaced, within a 5-year period. This would leave the Northeast as the only region consuming significant amounts of oil in the residential/commercial sectors in 1990.

---

[1] Double-counting was eliminated in the following way. If x is the fraction of a particular type of oil in a given sector that can be replaced with fuel switching and y is the fraction that can be replaced through increased efficiency, then the composite fraction is $z = x + y(1-x) = y + x(1-y) = x + y - xy$.

[2] Although there are secondary effects resulting from reduction of electricity use through greater efficiencies, these are accounted for in OTA's alternative projections for demand for electricity.

In addition to the direct oil savings, increased efficiency by residential and commercial natural gas customers could free up natural gas with the energy equivalent of 0.25 million barrels per day (MMB/D) and the industrial gas customers could save an additional 0.65 MMB/D. If, in addition to these savings, natural gas production or imports could be increased, then additional oil could be replaced by natural gas. The most likely uses for this additional gas would be in small industrial boilers and, perhaps, in some residential and commercial buildings in the Northeast, provided that some additional pipelines were built. OTA did not, however, include this possibility in estimating the oil replacement potential.

Table 22 compares the consumption of various types of petroleum products, natural gas, and solid fuels (mostly coal and wood) before and 5 years after the onset of the shortfall, assuming that the oil replacement scenario in figure 41 is implemented. Natural gas consumption increases by up to 11 percent, depending on the extent to which efficiency of natural gas use increases, while solid fuel use increases by 13 percent over this period. With respect to oil products, the most dramatic changes are the halving of residual oil consumption (as a percent of total oil consumption), the relative increase in gasoline consumption from 36 to 39 percent, and the reduction in distillate heating oil from 7 to 3 percent of total consumption. Also, diesel fuel as a percent of distillate fuel oil consumption increases from 62 to 81 percent.

Small refiners will have the most difficulty adapting to these changes, since they produce more residual oil and less high-grade diesel and gasoline than the average. However, a comparison of the 1990 product slate with recent domestic production of petroleum products[3] indicates that the larger U.S. refineries could accommodate the changes, provided that a large part of the reduction in residual oil consumption were accommodated through reduced imports of that fuel. (Imports of residual fuel oil in 1982 were 0.8 MMB/D.) The most difficult aspect of the changes may be the increase in diesel production, as a percent of total distillate fuel; and it is unclear to what extent this can be accomplished without a significant reduction in the quality of the diesel fuel produced.

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[3] "Monthly Energy Review," Energy Information Administration, DOE/EIA-0035(83/10), October 1983.

Table 22.—Changes in Fuel Consumption Through Fuel Switching and Conservation

	1985 consumption		1990 consumption	
	(MMB/D[a])	(percent)	(MMB/D[a])	(percent)
Residual	2.2	14	0.9	7
Distillate				
Diesel	1.8[b]	11	1.7[b]	14
Other	1.1	7	0.4	3
Gasoline	5.7	36	4.8	39
Kerosene	0.1	0.8	0.03	0.2
LPG and ethane	1.0	6	0.8	6
Subtotal	11.9	74	8.6	69
Other	4.1	26	3.8	31
Total	16.0	100	12.4	100

	1985 oil-consumption (MMB/D oil equivalent)	1990 consumption (MMB/D oil equivalent)	Percent change
Natural gas[c]	9	9-10	0-11
Solid fuels[d]	9.3	10.5	13

[a] 1B = $5.5 \cdot 10^6$ Btu.
[b] In 1985 diesel is 62 percent of the distillate oil, while in 1990 it increases to 81 percent.
[c] The range corresponds to the possible range of increases in efficiency of natural gas use. The lower numbers correspond to the case where feasible increases in efficiency of natural gas use are implemented.
[d] Coal and wood.

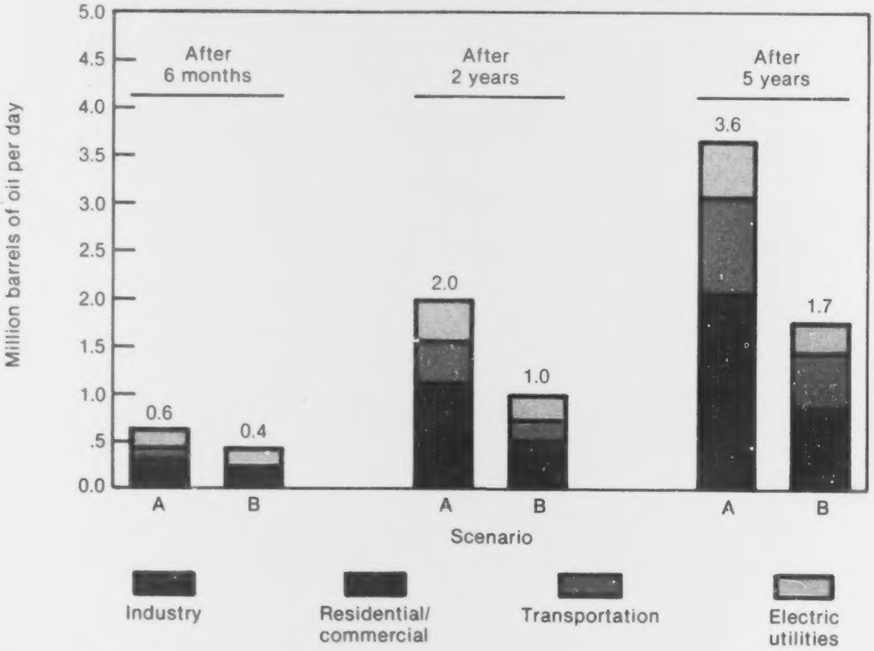
SOURCE: Office of Technology Assessment.

ALTERNATIVE SCENARIOS

A number of assumptions were made in order to derive the scenario for the technical oil replacement potential, shown in figure 40. The most important of these were that: 1) an increment of 2 trillion cubic feet per year (TCF/yr) of natural gas would be available through increased efficiency of natural gas use, increased domestic production, and/or increased imports; 2) oil users would invest in replacement technologies at the rate that they could be supplied; and 3) economic recovery in the United States would increase oil consumption to 16 MMB/D by 1985, up from 15.1 MMB/D in 1983. In addition, it was assumed that priority would be given to conversions from oil to solid fuels over conversions from gas to solid fuels in large industrial and utility boilers. In the following OTA considers variations on these assumptions and indicates the resultant changes in the amounts of oil replaced.

It is possible that capital shortages, unfamiliarity with alternative fuel technologies, uncertainty about future fuel prices and demand for industrial products, as well as a general reticence to make large investments during an (at least temporary) economic downturn, would limit investments to well below that which is technically feasible, unless additional incentives were provided. The failure to invest in increased efficiency of natural gas use could also lead to lower incremental supplies of natural gas. In order to illustrate the effect of a slower investment rate, OTA formulated another scenario (to be called scenario B, as distinct from the technically feasible response, scenario A). In this slower response scenario, it is assumed that oil users will invest in oil replacement technologies at one-third the rate that is technically feasible, that incremental natural gas availability would be one-third of the 2 TCF/yr assumed in figure 41, and that new car sales would drop to 5 million units per year. Together, these changes would reduce the amount of oil replaced at the end of 5 years from 3.6 MMB/D to 1.7 MMB/D, as shown in figure 41.

Figure 41.—Potential Reductions in Oil Consumption



SOURCE: Office of Technology Assessment.

Another variation on the basic scenario could occur if U.S. oil consumption does not reach 16 MMB/D by 1985. The most important changes in oil consumption (as compared to that assumed in deriving the above scenarios) would probably be reduced consumption in utility boilers and in industry. This would reduce the amount of oil that could be replaced in utility boilers (0.6 MMB/D in scenario A) and through increased efficiency of industrial processes (0.15 MMB/D in scenario A). On the other hand, switching from oil to gas in industrial boilers was limited by natural gas availability; and even if the amount of oil consumed in industrial boilers were lowered by 25 percent through reduced use, the oil replacement potential from industrial boilers would be nearly the same as was derived in scenario A (0.7 MMB/D). In all, changes under this variation might reduce the oil replacement potential to about 3.1 MMB/D; but the reduced demand for oil (in 1985) would also tend to reduce the severity of an international oil shortfall and would thereby reduce the amount of oil that would have to be replaced in the United States.

A final area to consider is the potential competition for the equipment and engineering manpower needed to convert large oil- and gas-burning utility and industrial boilers to solid fuels. In OTA's scenarios, it has been assumed that the oil-consuming boilers would have priority; but the rise in gas prices accompanying the oil shortfall and the increased demand for gas would also provide incentives to convert large gas-fired boilers to solid fuels. OTA's analysis indicates that equipment and manpower would be sufficient to convert industrial boilers consuming 0.2 MMB/D and utility boilers consuming roughly 0.3 to 0.4 MMB/D[4] of oil to solid fuels within 4 years of the onset of an oil disruption (including a 2-year delay before the first conversions would be complete). At this point, the estimated market for conversions of large oil-fired boilers would be saturated. Consequently, in the fifth year, large gas-burning boilers consuming the energy equivalent of 0.2 to 0.3 MMB/D could also be converted. Beyond this level, however, demand for the equipment and manpower needed for gas-fired boiler conversions within the 5 years could reduce the number of oil-fired boiler conversions that could be completed; but it seems likely that the total amount of oil that could be replaced would still be around 3.2 MMB/D or more.

LONGER TERM EFFECTS

Five to ten years after the onset of the shortfall, a number of additional things would happen. Some enhanced oil recovery projects begun after the onset of the shortfall would begin to produce oil (an increment of almost 1 MMB/D) and some synthetic fuels plants might begin producing (perhaps 0.5 MMB/D after 10 years). These projects might be delayed, however, because they would have to compete for some of the same resources, such as for engineering and construction firms and boilers and particulate control systems, that are needed for some of the fuel switching that would occur during the initial 5-year period. (Needless to say, this competition could also delay the fuel switching projects.) Nevertheless, it is probable that new and potentially large sources of liquid fuels would begin to appear.

Because of the decline in conventional U.S. oil production, however, total domestic supplies of liquid fuels could still be dropping. In particular, OTA has projected[5] that, under more or less normal circumstances and with 1.5 to 2.5 MMB/D of enhanced oil recovery, U.S. oil production in the year 2000 would drop to 4 to 7 MMB/D, down from a little over 10 MMB/D in 1983. Although the drop could be reduced somewhat through increased exploration and development of conventional oil, more enhanced oil recovery, and synthetic fuels production, it is far from certain that these measures would be adequate to prevent a significant drop in the domestic supplies of liquid fuels. Furthermore, since U.S. oil consumption in 1990 would be 12 to 13 MMB/D (after the replacements in fig. 40), oil imports could still be a significant fraction of U.S. oil supplies in 2000, unless additional measures are taken in the 1990s to reduce oil consumption.

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[4] This number is imprecise because both boiler conversions and completion of new powerplants currently under construction will contribute to the replacement of oil used in utility boilers; and there is no precise way to allocate the fraction attributable solely to boiler conversions. The estimate given is based on the relative capacity of converted boilers to that of new powerplants. However, if less capacity is converted, the amount of oil replaced will not drop in proportion to the reduction in converted capacity, because the last increments of nonoil capacity would be used primarily to satisfy winter and summer peak demand, and their yearly capacity factors would be small. Of course, the same thing would apply to new powerplants that may not be completed.

[5] *World Petroleum Availability (1980-2000)—A Technical Memorandum* (Washington, DC: U.S. Congress, Office of Technology Assessment, OTA-TM-E-5, October 1980).

Aside from the environmental impacts, which are described in chapter IV, the principal longer term consequences of fuel switching will be inflationary pressures on natural gas and food and an acceleration of the shift to nonpetroleum fuels. If natural gas production falls sharply in the 1990s, the increased dependence on gas brought about by oil replacement will greatly increase natural gas prices and/or imports. But, if production capacity remains at current levels or higher, or a slower drop in production is coupled with feasible increases in the efficiency of natural gas use, price pressures will be lower and a more orderly transition to increased use of coal, electricity, and renewables can occur.

As with oil, there is considerable uncertainty about future supplies of natural gas. OTA estimates that conventional natural gas production in the United States could range from 9 to 19 TCF/yr in the year 2000.[6] The higher limit is greater than the 1982 consumption of 17.8 TCF and considerably above the 1983 consumption of about 16 TCF. In addition, there may be significant supplies of unconventional natural gas, although OTA has not completed its assessment of the potential from these sources. Thus, there is a possibility that natural gas production could be maintained at recent levels through the year 2000, but this is far from certain.

Supplying the grain feedstocks for 5 billion gal/yr of ethanol production (capable of replacing about 0.1 MMB/D of oil) will lead to increases in farmland and food prices, which will persist as long as the feedstocks are supplied. Although the level of the change cannot be calculated precisely, most estimates indicate that U.S. food costs would be about $20 billion/yr higher with this level of ethanol production than they would be otherwise. (This compares to total civilian expenditures for farm foods of about $300 billion/yr.) On the other hand, if ethanol production is kept below about 2 billion gal/yr, the impact on food prices probably will be relatively small because most of the increased grain production could be accommodated by replacing soybean with corn production. In this case, the total area of farmland under intensive cultivation would not have to increase as sharply (per gallon of ethanol produced) as would be necessary for the higher level of ethanol production.[7]

Finally, over the long term, the forced reduction in oil consumption and the replacement of oil with nonpetroleum fuels and increased efficiency will accelerate the transition that must occur in the 1990s (as domestic oil production falls) if the United States is not to remain heavily dependent on imported oil.

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[6] *U.S. Natural Gas Availability: Conventional Gas Supply Through the Year 2000—A Technical Memorandum* (Washington, DC: U.S. Congress, Office of Technology Assessment, OTA-TM-E-12, September 1983).

[7] *Energy From Biological Processes* (Washington, DC: U.S. Congress, Office of Technology Assessment, OTA-E-124, July 1980); and *Energy From Biological Processes, Volume II: Technical and Environmental Analyses* (Washington, DC: U.S. Congress, Office of Technology Assessment, OTA-E-128, September 1980.

Chapter VII

Economic Impacts

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Chapter VII
Economic Impacts

INTRODUCTION

A permanent curtailment of imported oil would have widespread economic impacts throughout the entire U.S. economy. These can be projected by using a macroeconomic model to aggregate and integrate information about technology and investment behavior into a system that simulates the national economy.

Macroeconomic models exist with many different levels of detail. Some use the simplest extrapolations of history and, of course, this is what most people do implicitly when they plan for the future. Other models have thousands of equations and hundreds of key parameters. The choice among the many existing models depends on the blocks of input information available and the analytical objectives. Since this is primarily an assessment of technology, and since technology is industry- and process-specific, OTA has chosen to employ a relatively large computer model of the macroeconomy that can trace fuel inputs to many economic activities, industry by industry and end-use by end-use.

The analysis is based on two types of future projections. Both cover the same period, 1985-90, but one assumes an oil import reduction of 3 million barrels per day (MMB/D), and the other a normal flow of oil imports. The normal scenario serves first to test the model and second to establish a baseline or reference case for comparison to shortfall scenarios. Shortfall scenarios are more difficult to simulate because macroeconomic models are based on historical trends and such trends may be substantially altered by the postulated oil supply shortfall. However, some confidence may be placed in their continuation, despite a shortfall, based on the analysis in chapter III, which showed that the shortfalls in 1973-74 and 1978-79 mainly affected energy consumption patterns by accelerating trends that were already evident.

Before describing the model, OTA acknowledges that all macroeconomic projections are uncertain because every projection (either implicitly or explicitly) involves complex trends in demography, labor markets, technology, consumer preferences, international trade, and so on. The widely publicized failure of prominent macroeconomic models to forecast events in the early 1980s confirmed once again that such prediction is very difficult. Nevertheless, despite the difficulties, the exercise of a formal computer model can be instructive if it illustrates plausible economic relationships that are closely related to the user's primary concerns.

One key concern is the 5-year timeframe, because it has significant implications for model choice. The most familiar macroeconomic models—Data Resources Inc., Chase Econometrics, Wharton Econometrics—provide more or less detailed, quarter-by-quarter accounts of national and regional economic activities because most of their users make private investments or policy decisions within a 2-year timeframe. In these models, money supply and demand, interest rates, product inventories, and retail sales receive considerable attention because each of these variables has major impacts on the rest of the economy in the short run.

For the longer term problem, most cyclic phenomena wash out, and what matters most are trends in variables such as investment, the rate of growth in labor productivity, the long-term accumulation of government debt, consumption patterns, savings rate, technological progress embodied in new capital, average rates of return on capital, and all of these variables compared to related trends abroad. The concern with oil dependence also leads to an emphasis on energy-using technologies, the relative prices and supplies of domestic oil and alternative fuels, and market opportunities for substituting capital and labor for energy which will become profitable as the price of oil rises.

The details of OTA's midterm perspective (5 to 10 years) are presented below. The main point here is that OTA's analysis does not consider in detail important economic impacts and adjustments immediately following an oil supply shortfall. By omitting them, primary attention can be focused on the expected changes in the technology embodied in the economy's base of capital stock, how rapidly these changes can occur, and how much they may cost. Such information (about the long term) can however, play an instrumental role in organizing emergency behavior during the economic crisis immediately following such a disrupting event. For example, if the longer term market clearing prices from oil can be roughly estimated, it suggests that short-term prices significantly above that level should be moderated by a drawdown of the Strategic Petroleum Reserve. Furthermore, however the economy makes it through the short-run turmoil, the longer term trends are presumably what should matter most when making strategic judgments about foreign policy (including military deployment), both of which in 1984 are predicated to a great extent on the goal of protecting political and economic stability in the oil-producing Middle East.

THE INFORUM MACROECONOMIC MODEL OF THE U.S. ECONOMY

Among the current, mid- to long-term models available, the INFORUM model, resident at the University of Maryland in College Park, was chosen primarily because of its low-cost flexibility in simulating technological change. Like all such models, its structure and initial parameter specification are based on historical experience and economic theory. At the minimum, the introduction of a formal computer model, with its conventions for the consistent definition of variables and aggregates, provides a large accounting framework or map that can be manipulated at relatively low cost in order to trace economic impacts from an oil supply curtailment. This section outlines how this accounting is accomplished.

The Macroeconomics Without Energy Detail

The INFORUM model like all macroeconomic models, makes a fundamental distinction between producers and consumers (see fig. 42, Frame A). Consumers consume goods and services that industries produce, and supply in return the labor and capital resources necessary for production. This circuit of physical flows is complemented by a parallel system of money flows. As shown in figure 42A, money flows in the opposite direction from goods and services since the latter are exchanged for business revenues, and labor and capital are exchanged for wages, salaries, profits, interests, capital gains, and other forms of return on financial assets.

Notice that at this most elementary level the domestic economy is viewed as an integral or closed system. The interaction of producers and consumers (via both physical and monetary flows) constitutes the basic structure and the basic dynamics of the economy. The first part of this section describes the basic structure and dynamics in greater detail and then adds to it foreign exchange and governmental activities. The second part describes how energy flows enter into this larger economic framework.

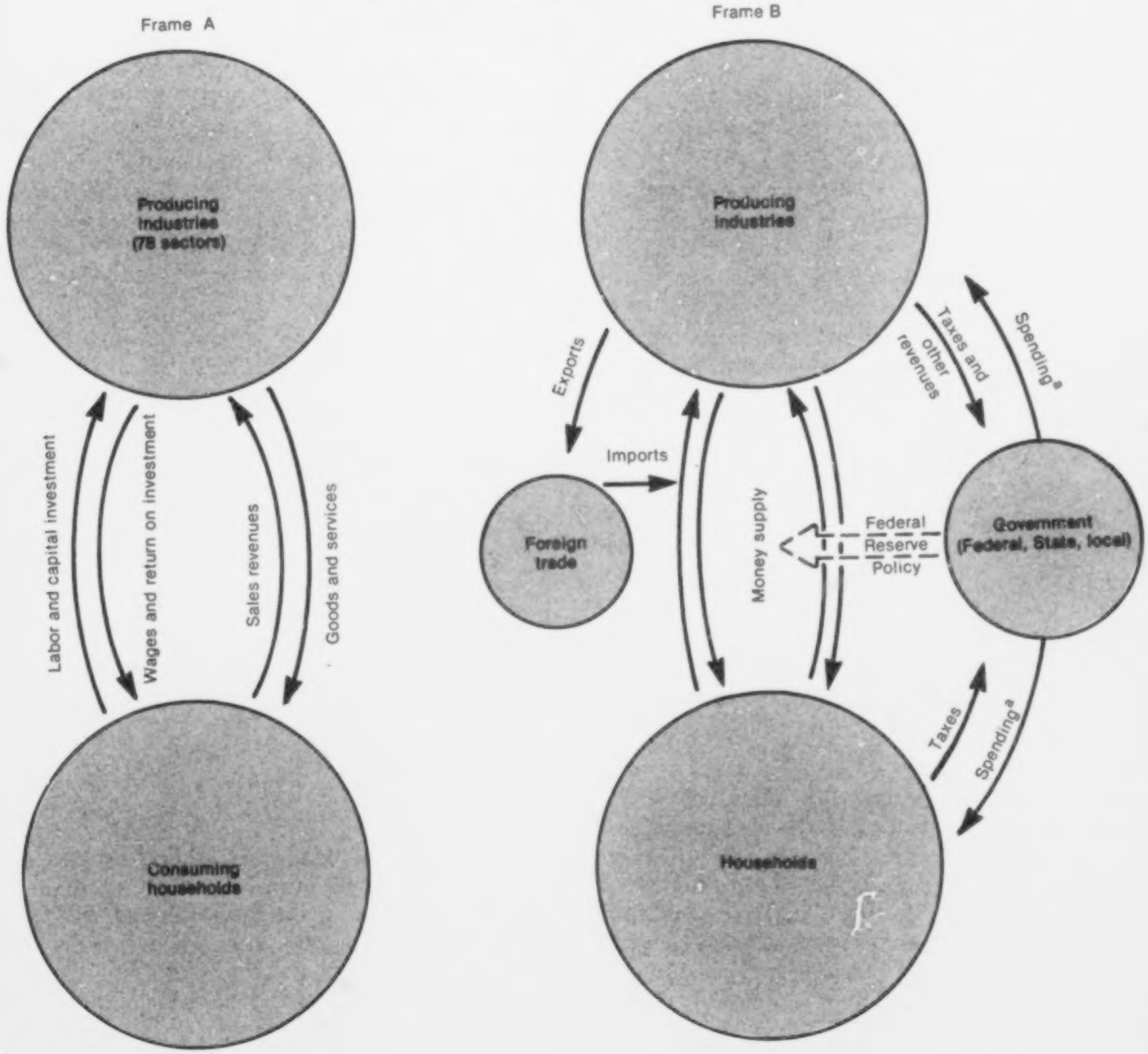
Industrial Input/Output

The core of the INFORUM model is an input/output matrix that represents the activities of 78 distinct industries plus final demands. Final demands are purchases by consumers for personal consumption, by investors for the installation of plant and equipment, by the Government for implementation of governmental programs such as national defense, and by exporters for sales abroad. Numbers in each cell of the matrix (the input/output coefficients) allow the computer to track flows of all resources, goods, and services. OTA adjusted these material flows to incorporate technological replacement of oil into future economic projections.

Total Consumption and Consumer Demand Patterns

The model contains econometric demand functions for each of the 78 product categories. These

Figure 42.—Model of the U.S. Economy


Frame A
Producing industries (78 sectors)
Labor and capital investment
Wages and return on investment
Sales revenues
Goods and services
Consuming households
Frame B
Producing industries
Exports
Imports
Foreign trade
Money supply
Federal Reserve Policy
Taxes and other revenues
Spending[a]
Government (Federal, State, local)
Taxes
Spending[a]
Households

[a] Includes both consumption and investment.

SOURCE: Office of Technology Assessment.

determine the quantity consumed in terms of the product price, personal disposable income, total number of consuming households, and in some cases the prices of products that are either good substitutes or complements. If two goods substitute for each other, then a price increase for one will increase demand for the other, and vice versa for complements. These consumption demands and the associated consumer goods markets are illustrated as the exchange relationship on the right hand side of figure 42A. Along with investment functions (see below), these demand functions collectively drive the model by determining the volume and composition of goods and services over time.

Product prices and personal disposable incomes are determined as a result of the modeling exercise. The number of households is given to the model by assumption. Through 1995, the U.S. population is projected to grow 0.8 percent per year, with faster growth in the next few years and slower later on. This is important in projecting and evaluating economic growth because population growth tends to expand the economy and because total personal income must grow by at least this rate in order to maintain the level of income per capita.

Rest of the World

Trade with the rest of the world increases the effective size of the resource base and thus increases potential gross national product (GNP) and real income. The larger the volume of trade activity, the greater the base of world resources made available to U.S. producers and consumers. In terms of figure 42B, other things being equal, an increase in the size of the circle labeled "Foreign Trade" increases industrial production or household consumption or both.

The U.S. balance of trade (including both services and merchandise) and the technological composition of exports and imports are becoming increasingly important factors in long-term prospects for U.S. economic growth because the volume of trade has increased as a share of total economy activity and because imports are increasingly competitive in high-growth, high-technology industries. While there is considerable uncertainty about how these trade patterns will evolve, OTA derives trade patterns using behavioral functions included in the INFORUM model. As discussed below, these functions call for a more or less even balance between imports and exports and for roughly the same composition of exports and imports into the foreseeable future, with and without an oil supply shortfall. To evaluate the potential importance of this assumption, it is noteworthy that exports and imports each amounted to about 11 percent of GNP in 1982 and that oil imports amounted to just under 18 percent of the total imports.[1]

Inflation and Government Fiscal and Monetary Policies

The activities of government constitute a second major adjunct to the basic national economy (fig. 42). Governments (e.g., local, State, and Federal) tax firms and households in order to provide public goods and services (e.g., national defense, public assistance, and schools), and this affects both the distribution of resources among productive activities, the size of total economic activity, and the distribution of income among households. The net impact on the economy of taxes and Government expenditures is commonly summarized under the heading of **fiscal policy.**

For this study Federal fiscal policy is assumed to be unchanged from 1982 for all future projections. While this may be unrealistic, as discussed below in the context of shortfall scenarios, the purpose in leaving it unchanged is to avoid introducing perturbations other than the oil supply curtailment and the technological and oil price responses to it. Please note that although fiscal policies (tax structure, spending, and transfer programs) remain unchanged, the Government deficit will vary, depending on the performance of the economy.

The Federal Government also performs a second, unique function when it prints money and regulates the banking and securities industries. The principal regulatory agency involved is the Federal Reserve Board, and its principal policy instrument is to regulate the **money supply.** As illustrated in figure 42B (the shaded area in between producers and consumers), the money supply is the central medium of business exchange. As money supply expands relative to the volume of goods and services exchanged, it tends to increase prices; and such price increases can lower real interest rates and stimulate economic activity if investors are optimistic **and** if there are unemployed resources. A relative expansion in the money supply can also cause general price inflation and raise interest rates if investors are pessimistic **or** if other resources are not available to increase production.

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[1] *Survey of Current Business,* National Income and Product Accounts, October 1983, tables 1.1, 4.1, and 4.3. While 11 percent of the GNP may seem like a small share in a firm's or household's operating budget, it looms large in the context of national income accounts. From the latter viewpoint, a 1-percent decline in GNP is a major political event, one that would result from only a 10-percent decline in exports.

While the net effects of monetary policy can be large, the current academic and political debate leaves much uncertainty about both monetary policy and price inflation in the future. Because key issues are unresolved, the model makes the elementary assumption, except for transient instability, that inflation equals the difference between the growth in money supply and the growth in real GNP or the value of output measured in constant prices. In all scenarios, the supply of money (M2) is assumed to grow at a constant rate of 8 percent per year. Other rates might have been used, depending on Federal Reserve policy, but that would only affect this model's projected inflation, not the size or structure of economic activity. Because it serves (in effect) as the bottom-line measure for economic performance, growth in real GNP will be discussed by itself later in this section.

Gross Investment and Interindustry Investment Patterns

Firms, households, and governments decide more or less independently how much purchasing power is set aside and used to increase future production capacity (i.e., capital stocks), and then how to divide these capital funds between alternative long-lived material assets and human resources. These decisions or investments determine the future productivity of the economy. The investment choice, as reflected in aggregate national income accounts, is among residential structures, nonresidential structures, and producer-durable equipment.[2] The model also breaks down investment behavior by the 78 producing sectors, a level of detail that allows accounting for the capital cost of oil replacement.

Employment and Unemployment

In both the short and long run, the number of employed people tends to move in step with the real GNP. The relationship of real GNP to unemployment, however, is more complex. In the short term, during business cycles, unemployment moves in the opposite direction to the rate of growth in GNP. In the long term, however, the GNP/unemployment picture depends on the relative growth trends of the labor force and the GNP. As demonstrated during the past 15 years, even though the GNP grows along a positive long-term trend, growth in the labor force (including greater participation by women) can be greater, and thus the unemployment rate can increase.[3]

In the long term it is also important to distinguish growth rates among different types of economic activity. Depending on long-term trends in international competition, in technology change, and in the product mix for domestic consumption, jobs may be created at a faster or slower rate per dollar invested, and jobs may be of relatively high or relatively low productivity. In general, however, the greater amount of total investment in productive assets, the more rapidly the Nation's base of plant and equipment expands and thus the more jobs are created.

Real GNP

Real GNP is the commonly accepted principal measure of national economic well-being. From the point of view of demand for goods and services, it is the main single factor driving oil consumption. From the point of view of the supply of goods and services, GNP rises or falls depending on the availability and price of oil. However bewildering this might seem, the GNP (or the level and composition of economic activity) is both the **cause** and the **effect** of oil consumption. In National Income and Product Accounts kept by the U.S. Department of Commerce, estimated

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[2] Investment in people, via general education and vocational training, is at least as important for future economic productivity as investment in material assets, but national accounts (in general and in the model) fail to treat such investment systematically because education has many noneconomic as well as economic objectives, and otherwise because it is much more difficult and controversial to measure human beings in terms of dollars.

[3] See *Survey of Current Business*, October 1983, p. 8, table 10, for GNP/unemployment trends and cycles over the past 30 years.

GNP amounts to the simultaneous summation and equilibration of all forces that create demand and supply for goods and services.

However, as a measure of economic welfare during an oil disruption, GNP omits important economic services or activities as well as important elements in the perception of well-being. For example, it does not measure services of long-lived consumer durables such as private automobiles, which would be significantly curtailed during an oil shortfall by the high cost or actual shortage of gasoline. To this extent, estimated GNP decline following onset of a shortfall would underestimate the true loss in economic welfare.

On the other hand, GNP also does not include the value of domestic services by family members, production from gardens, direct barter, and various special sharing arrangements, all of which tend to expand in times of social stress. These activities help to explain how most people get along quite nicely during emergencies despite apparent hardships, by learning how to get more utility from the limited material and human resources that do remain available. To the extent that GNP does not measure the enhanced human adaptability that such activities represent, its apparent decline following an emergency such as an oil import curtailment can overestimate the actually perceived loss.

The INFORUM Energy Skirt

For this study, OTA disaggregated total energy consumption (or, depending on one's perspective, aggregated energy consumption by end-use technology) into the five major end-use sectors: residential, commercial, industrial, transportation, and electric utilities (chs. III through V). These distinctions are maintained in the formal model, within a larger economic framework.

Sometimes this economic framework calls for merely changing names, such as when residential consumption of heating oil is called "personal consumption expenditure" for heating oil. Other times, it involves a more important reorganization from technological to market relationships, such as the redistribution of technologically similar transportation activity into SIC (Standard Industrial Classification) sectors and other end-user categories. For example, the chart in figure 43 gives this additional information about how oil is used.

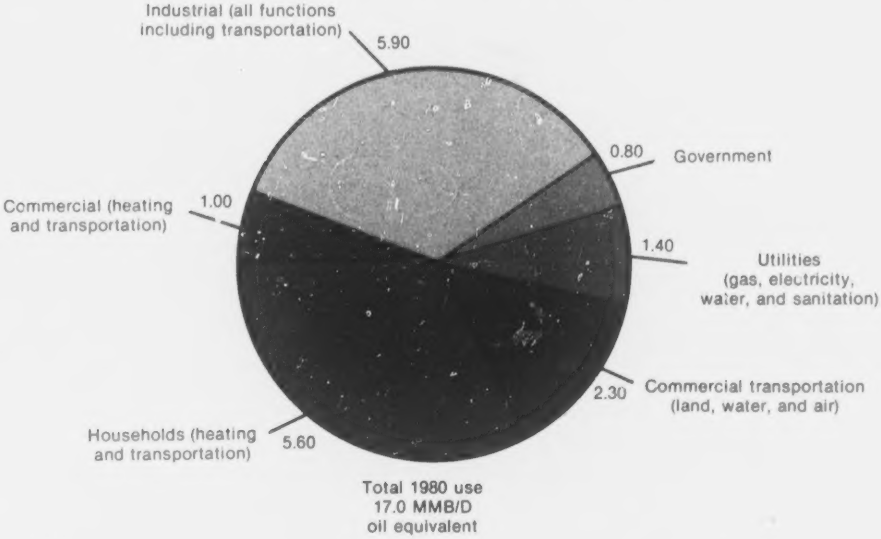
This type of reorganization of energy flows is an essential first step in understanding how sharply rising oil prices can increase the cost of products with oil inputs and decrease real personal income. In general, translations of engineering into market concepts is necessary to pursue the economic logic behind what the economy does with oil-replacing technology and with technology in general in the event of a disruption.

For example, consider again the two products made from petrochemicals, plastic contact lenses and milk bottles, which were initially described in chapter III. Both types of manufacturing start with a commodity chemical (resin pellets) whose chemistry is adjusted after melting so that it can be resolidified and molded into the desired chemical structure and physical shape. The plant that makes milk bottles, however, will be handling a much larger volume of plastic material, which means in general that it will be using more petroleum feedstock and process heat (gas or oil) per dollar of product sales. The plant making contact lenses pays a much higher percentage of its costs for the precisely engineered machinery and skilled labor necessary to meet more complex and precise standards for product quality. Consequently, the bottle plant manager is likely to be more aware of energy costs and more likely to switch fuels or to add energy-conserving retrofits as energy costs rise.

It is an important part of this modeling exercise that industry be sufficiently disaggregated to allow detailed simulation of fuel switching and conservation, as projected in the previous chapters. The model also simulates another important path for oil replacement, product mix shift. The comparison between contact lenses and milk bottles again illustrates the point.

If products made from chemicals are more like contact lenses, then oil savings in the chemicals industry will be difficult to achieve by raising oil prices because the net affect on the price paid by the final consumer is relatively small and, in any case, final consumers have no practical alter-

Figure 43.—1980 Petroleum Consumption by Sector



SOURCE: Energy Information Administration, *1982 Annual Review of Energy*, Washington, DC, April 1983, table 3, p. 69.

native. Just the opposite is true if products made from chemicals are more like plastic milk bottles. In that case, oil price increases significantly drive up the cost of final consumer goods, and furthermore, consumers have good alternatives. While these two goods are not commonly used as standards for comparison in the chemicals industry, they nonetheless illustrate the importance of product mix. The model incorporates a complete spectrum of product substitutions and calculates a full set of market-based opportunities for oil savings via product mix shift.

Because of this study's primary focus on energy-related economic transactions, OTA has appended an "energy skirt" to the INFORUM model. This additional block of data is called a skirt because it figuratively hangs below the basic input/output table, providing greater energy detail for each of the 78 industries and for personal consumption, investment, and government expenditures. Normally, this model identifies only two petroleum products, fuel oils and all other refined products, and provides no information about how these or other fuel products are used. The skirt identifies six petroleum product categories and a variety of energy end uses that are common to many industries (see table 23). Both kinds of additional information clarify opportunities and constraints for improvement in fuel efficiency and fuel switching (see table 24 for an illustrative skirt tableau).

Table 23.—Petroleum Products and End Uses Common to Many Industries

Energy end use functions	Petroleum products
1. Transport	1. Light hydrocarbons
2. Space conditioning and lighting	2. Gasoline
3. Boilers	3. Distillate fuel oil (#2)
4. Process heat	4. Kerosene
5. Other engines	5. Residual fuel oil (#6)
6. Materials inputs	6. Other products
7. Other	

SOURCE: Office of Technology Assessment.

Energy skirt data have been obtained from many different sources, but the initial specification for base year 1980 was taken from the Energy Disaggregated Input/Output Data Base provided by the Departments of Commerce and Energy.[4] Because the latter was compiled and documented

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[4] "Detailed Input-Output Energy Make and Use Data: 1977 and 1980; for the Bureau of Labor Statistics I-O Model and the Department of Energy EDIO Model," contract No. BLS 82-506, January 1983, prepared by Jack Faucett Associates.

Table 24.—Illustrative Energy Skirt Table for 1982: Flows in 1977 Dollars, Quantities and Btu

	14 Printing											
	1 Coal (th tons)	2 Crude P (th bbl)	3 Nat gas (b cu ft)	4 L. hydr (th bbl)	5 Gasoline (th bbl)	6 Distil (th bbl)	7 Kerosene (th bbl)	8 Resid (th bbl)	9 Oth Petr (th bbl)	10 Elect (mil kwt)	11 Gas util (b cu ft)	12 Total
Transport												
$	0.0	0.0	0.0	0.0	68.4	12.9	0.0	0.0	0.9	0.0	0.0	82.2
Q	0.0	0.0	0.0	1.9	4,359.4	910.5	0.0	0.0	51.2	0.0	0.0	5,323.0
Btu	0.0	0.0	0.0	0.0	22.9	5.3	0.0	0.0	0.3	0.0	0.0	28.5
Boilers												
$	0.7	0.0	0.0	0.0	0.0	10.0	0.0	7.2	0.0	0.0	16.1	34.0
Q	26.8	0.0	0.0	0.0	0.0	680.6	0.0	543.9	0.0	0.0	8.5	1,224.5
Btu	0.7	0.0	0.0	0.0	0.0	4.0	0.0	3.4	0.0	0.0	8.7	16.8
Process heat												
$	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	48.2	48.2
Q	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25.6	0.0
Btu	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.2	26.2
Other												
$	0.0	0.0	0.0	2.5	0.0	0.0	0.0	0.0	0.0	265.9	0.0	268.4
Q	0.0	0.0	0.0	228.0	0.0	0.0	0.0	0.0	0.0	9,111.3	0.0	228.0
Btu	0.0	0.0	0.0	0.9	0.0	0.0	0.0	0.0	0.0	31.1	0.0	32.0
Total												
$	0.7	0.0	0.0	2.5	68.4	22.9	0.0	7.2	0.9	265.9	64.3	432.7
Q	26.8	0.0	0.0	230.0	4,359.4	1,591.1	0.0	543.9	51.2	9,111.3	34.1	6,775.6
Btu	0.7	0.0	0.0	0.9	22.9	9.3	0.0	3.4	0.3	31.1	34.9	103.4

	15 Agriculture fertilizers											
	1 Coal (th tons)	2 Crude P (th bbl)	3 Nat gas (b cu ft)	4 L. hydr (th bbl)	5 Gasoline (th bbl)	6 Distil (th bbl)	7 Kerosene (th bbl)	8 Resid (th bbl)	9 Oth Petr (th bbl)	10 Elect (mil kwt)	11 Gas util (b cu ft)	12 Total
Transport												
$	0.0	0.0	0.0	0.0	5.8	2.6	0.6	0.0	0.1	0.0	0.0	9.1
Q	0.0	0.0	0.0	0.4	372.4	185.1	40.7	0.0	5.0	0.0	0.0	603.7
Btu	0.0	0.0	0.0	0.0	2.0	1.1	0.2	0.0	0.0	0.0	0.0	3.3
Boilers												
$	4.9	0.0	0.0	0.0	0.0	6.7	0.0	19.9	0.0	0.0	236.3	267.7
Q	260.0	0.0	0.0	0.0	0.0	493.1	0.0	1,760.7	0.0	0.0	185.9	2,253.9
Btu	6.5	0.0	0.0	0.0	0.0	2.9	0.0	11.1	0.0	0.0	190.2	210.6
Process heat												
$	0.0	0.0	0.0	0.0	0.0	1.2	0.0	0.0	0.0	0.0	101.3	102.4
Q	0.0	0.0	0.0	0.0	0.0	87.0	0.0	0.0	0.0	0.0	79.7	87.0
Btu	0.0	0.0	0.0	0.0	0.0	0.5	0.0	0.0	0.0	0.0	81.5	82.0
Materials												
$	0.0	0.0	0.0	5.8	0.0	0.0	0.0	0.0	0.0	0.0	384.0	398.8
Q	0.0	0.0	0.0	530.9	0.0	0.0	0.0	0.0	0.0	0.0	292.0	530.9
Btu	0.0	0.0	0.0	2.1	0.0	0.0	0.0	0.0	0.0	0.0	298.8	300.9
Other												
$	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	203.0	0.0	203.0
Q	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9,483.3	0.0	0.0
Btu	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.4	0.0	32.4
Total												
$	4.9	0.0	0.0	5.8	5.8	10.5	0.6	19.9	0.1	203.0	721.5	972.1
Q	260.5	0.0	0.0	531.3	372.4	765.3	40.7	1,760.7	5.0	9,483.3	557.6	3,475.5
Btu	6.5	0.0	0.0	2.1	2.0	4.5	0.2	11.1	0.0	32.4	570.4	629.1

SOURCE: Office of Technology Assessment (dollars are in millions, Btu in trillions).

for use in input/output analyses, it is uniquely suited for OTA's purposes as the most comprehensive and detailed accounting available of all energy flows within the U.S. economy.

The energy skirt helps calibrate and analyze macroeconomic simulations because its greater detail sharpens associations between economic activities and energy-using technology. For example, one of the most important distinctions between petroleum products is between distillate used for engines and distillate used for heat and steam. This functional distinction, which **cannot** be made with the INFORUM model without the skirt, is crucial in projecting opportunities for natural gas substitution. Natural gas is relatively easy to substitute for a large fraction of oil presently used for stationary heat/steam applications, but the opportunities for replacing distillate presently used in mobile engines are considerably more limited.

The skirt is especially well suited for tracking "intermediate" oil consumption (i.e., oil used in the production of other goods and services). In physical units, it traces oil flows through various stages of industrial activity so that it is possible to calculate the oil intensity of each of the 78 final product categories. In dollars, it tracks backward from the value of final products to derive the value of petroleum products used in their production. The two calculations, one in physical units and the other in dollars, are done in parallel as the model continues to shift the mix and the prices of final products (and thus intermediate oil consumption) until production costs for each of the 78 product sectors are balanced by the value of the product to consumers.

Before discussing the modeling exercise, however, it is important to mention that this model does not disaggregate energy and other commodity flows by region, nor does it address many important issues related to the development of local energy resources that are too small to be visible in national accounts (see box).

A MODELING STRATEGY BASED ON THE OTA TECHNOLOGY DATA BASE

The size and complexity of the INFORUM model suggests that OTA follow certain guidelines in order to integrate OTA's analysis of technology deployment while not losing an accurate, general perspective on the rest of the economy.

Three sets of guidelines were followed. First, energy technology deployment rates were explicitly inserted into the energy skirt and the input/output matrix in terms of specific coefficients. These coefficients serve as basic controls on how much the economy can produce, given limited oil supplies. Second, the rest of the input/output matrix as well as final demand functions and policy parameters of the INFORUM model were based on: 1) existing econometric work done by the INFORUM staff, 2) certain consistency checks on investment behavior and on overall model performance, and 3) comparisons to results from other macroeconomic models. Third, the energy and nonenergy parts of the model were integrated by a process of iteration where fuel prices and technology deployment rates were readjusted to be consistent and to achieve the required savings of 3 MMB/D in oil consumption. All three guidelines are elaborated in this section.

The Energy Sector Guidelines

Of all activities and technologies related to oil consumption, OTA focused primarily on two fuel product/end-use combinations or technology blocks: gasoline for automobile transportation and fuel oil (both #2 and #6) for heat and steam. These two technology blocks receive the most attention, as they have in the technology analysis above, because they offer the greatest economic opportunities to replace oil demand.

As discussed above, auto gasoline accounted for about 37 percent of total petroleum consumption in 1982, and so even a small percentage improvement in auto fuel efficiency or decline in vehicle miles traveled can cause a relatively large reduction in total oil consumption. The analysis in chapter V showed that recent dramatic improvements in new car fuel economy will steadily increase the fuel economy of the entire auto fleet (without further investment by automakers) as old cars are replaced over time by new cars. The technological improvements that increase fuel efficiency and fleet turnover were combined and programmed into the model, like all other technology and technology change, as fixed coefficients (for any given year) that change gradually over time.

In addition to changing technology, current economic studies indicate a strong relationship between personal consumption of gasoline and personal disposable income, and a weaker but still significant relationship between the same consumption variables and gasoline prices.[5] As

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[5] There is extensive economics literature dealing with the personal consumption of gasoline. For two recent surveys see Carol A. Dahl, *Survey of the Demand for Gasoline*, unpublished draft, Department of Economics, University of Wisconsin-Milwaukee, April 1983; and David L. Green, *The Aggregate Demand for Gasoline and Highway Passenger Vehicles in the United States: A Review of the Literature 1938-1978*, Oak Ridge National Laboratory, ORNL-5728, July 1981.

Local Development of Energy Resources

Faced with a need to alter petroleum use patterns, many communities and entrepreneurs will consider investing in local energy resources to meet local energy needs. The market incentive for local energy production will increase with rising oil prices, just as incentives rise for all types of oil replacement, but local energy development offers the possibility of reducing the outflow of consumer expenditures and lowering unemployment in regions which may already be economically depressed.

This issue is a subset question of the general question of local development. If local capital and labor are exported from a community, its economy suffers. Conversely, if capital (both local and imported) is put into investments in the community that improve labor utilization and productivity, the community prospers. From the community perspective, therefore, it is always advantageous to attract investments to the community if it has underutilized labor and capital that might otherwise go elsewhere. From the national perspective, however, that same capital and labor might be able to produce a higher added value if it were invested elsewhere.

In considering energy investments (or any investment) at the community level, it is important to consider factors that affect the overall well-being of the community. A site-specific analysis is required to see if the value added through the energy production is greater than that of an alternative product that might have been produced.* If it is not, the wealth of the community could increase more if the investment and labor go into the nonenergy industry. The value added by producing the nonenergy product would more than pay for importing the energy, which would then not be produced locally.

In economic terms, this question is clarified by the theory of comparative advantage. Trade between two locales, two regions, or two countries can be advantageous to both if relative prices for products traded are set so that each party can achieve a higher real income or standard of living. In other words, if each of the trading partners can produce some commodities at a lower cost than his trading partner, then it is mutually advantageous for each partner to concentrate on producing the commodities he produces at the lower cost and trade a part of the output for the commodities he does not produce. Relative prices may not, in fact, allow much mutual gain, especially following an oil disruption, when market conditions are highly unstable; but the advantage of trade is likely to obtain over time as market competition tends to set appropriate relative prices.

Aside from the questions of direct increases in wealth and insurance, some people place a high value on local production of energy because it allows local control over energy supplies, while centralized energy systems are beyond their control. These people believe that having a more direct control over the factors that influence their life is worth the added economic cost. From an economic point of view, however, there is no inherent advantage in having a local energy resource if the cost of the energy is higher than energy delivered through a utility or a larger-scale system. Capital resources diverted into producing local energy might better be invested in a competitive product that could bring employment and revenues and add to the productive base of the community. While the development of local energy sources will generate jobs in the short run, it is important to consider what types of jobs will be generated in the longer run, and whether the investment is the best use of available capital.

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*The calculation of the value of local energy production must include the value of using local resources and the value lost if these resources could be exported but are not. The calculation of value should also include the social value placed on being more independent of centralized energy supplies, over which the community has little or no control.

income rises (falls) vehicle miles traveled rise (fall). As petroleum prices rise (fall), vehicle miles traveled fall (rise). Both behavioral relationships are incorporated into the model as functions. For future projections, the income elasticity of personal vehicle miles traveled is set equal to +0.5, and the price elasticity is set equal to –0.2.[6] In other words, if personal disposable income goes up (down) by 10 percent, personal vehicular travel will rise (fall) by 5 percent. Similarly, if the price of oil rises (falls) by 10 percent, travel will fall (rise) by 2 percent.

This second mode for oil savings in auto transportation is more appropriately called oil conservation, not oil replacement, because it involves cutting back an energy service instead of maintaining service by alternative means. As a rational economic response to higher oil prices, it is an alternative to technological replacement; and to the extent that oil is not replaced with greater fuel efficiency in autos or efficiency gains and fuel switching anywhere else in the economy, it must be saved by cutbacks in driving and reductions in economic activity of all kinds.

Another behavioral relationship is also important, especially right after an oil shock. Experience with much smaller shortfalls during the past 10 years indicates that driving habits contain a discretionary component that can be at least temporarily eliminated during an emergency.[7] Although it can provide considerable savings in the short run, this opportunity for oil displacement is **not** included in the model since the model's focus is more long term.

Consumption for stationary heat and steam services accounted for only about half as much oil (about 18 percent), but it deserves attention because it may be cost effective to replace almost all of it with a combination of natural gas, electricity, and coal.[8] Natural gas is an especially important fuel substitute because, if an existing distribution pipeline is nearby, gas can provide heat and steam service with relatively small capital investment. Furthermore, the energy service to the full spectrum of heat and steam end users is at least as valuable as that provided by oil. Electricity is cost effective primarily when heat pumps can be used efficiently by small residential and commercial customers; and coal is an attractive oil substitute mainly in relatively large boilers.

Again, in terms of the model, fuel switching for heat and steam is accomplished in a manner exactly parallel to that of auto fuel efficiency. For the 78-sector, input/output matrix, fuel oil coefficients for heat and steam services are reduced over time to reflect a priori rates of deployment for fuel switching technologies. Corresponding increases in coefficients for gas, electricity, and coal inputs must also be made so that total fuel inputs are sufficient to supply demands for heat and steam services.

Unlike auto fuel efficiency, where oil replacement investment pays off into the future as the fleet follows its normal rate of turnover, most oil replacement in stationary heat and steam **does** require capital investment for that specific purpose after onset of the shortfall, as estimated in table 25. The broad range of plausible costs per barrel introduces major uncertainty about cost effectiveness, and thus major uncertainty about projections of the rate of replacement. Although there is also uncertainty about the rate and cost of oil replacement in transportation (minor, relatively high-cost investment options for replacing oil use in transportation are shown in table 26), over 80 percent of the difference in the postulated high- and low-response scenarios (see ch. VI) is due to uncertainties for oil replacement in heat and steam.

In the model, investment projections are based on investment functions that have been estimated from historical data. To some extent, these functions call for investment to rise with oil prices, in effect to support oil replacement as they have done in the past, but the primary determinant of investment is the level of production. If total projected investments for the seven key industries[9]

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[6] These elasticities fall in the midrange of recent econometric estimates.

[7] For estimates of discretionary oil savings related to personal auto use see National Petroleum Council, *Emergency Preparedness for Interruption of Petroleum Impacts Into the United States*, April 1981, ch. 2.

[8] This end-use category includes virtually all oil consumption by residential and commercial users, all oil consumption by utilities, and about 18 percent of industrial demands.

[9] These industries are food and tobacco, paper, agricultural fertilizers, chemicals, petroleum refining, ferrous metals, and nonferrous metals.

Table 25.—Estimated Investment Costs for Major Oil Replacement Technologies

Option	Investment cost (thousand 1983 dollars per barrel per day of oil replaced)
• Fuel switching in industrial and utility boilers:	
Conversion to solid fuel (including coal-water mixtures)	10-20
Construction of new solid fuel boiler with coal-handling facility	25-50
Construction of coal-water mixture production plant	2-3
Completion of new powerplants currently under construction[a]	50[a]
Conversion to natural gas	0-5
• Fuel switching in residential and commercial space heating and hot water:	
Natural gas	15-25
Electric heat pumps	35-60[b]
Electric resistance heating	10-20[c]
Solid fuel	5-35[d]
• Residential and commercial energy conservation:	
Building insulation	40-60[e]
• Industrial oil replacement:	
Amalgam of efficiency improvements and product mix shifts	10-70[f]

[a] Assumes $500 per kilowatthour to complete and plant operation at 70 percent of capacity.

[b] Based on an installation cost ranging from $2,000 to $3,500 for a system used only for space heating to $2,500 to $4,000 for a system for space heat and hot water and on the national average oil use of 676 gal and 1,055 gal per year for homes in which oil provides heat only, and both heat and hot water, respectively.

[c] Assumes $500 per household for electric resistance space heaters and $1,000 for a hot water heater.

[d] Assumes $250 to $750 for wood stove (including installation) for space heating only or $2,500 for new wood-fired central boiler for heat and hot water.

[e] This estimate represents an average over a number of building types and ages. Actual site-specific costs will vary from less than $1,000 per B/D up to over $200,000 per B/D.

[f] Industrial replacement involves a broad range for investment costs. At the low-cost end, investment is incidental (e.g., for product mix shifts); and at the high-cost end, investments are large because firms are willing to pay an insurance premium in order to increase the security or price stability of its fuel supplies.

SOURCE: Office of Technology Assessment and Gibbs & Hill, Inc., "Oil Replacement Analysis Phase I—Selection of Technologies," contractor report to Office of Technology Assessment, April 1983.

Table 26.—Estimated Investment Costs for Selected Oil Replacement Technologies in Transportation

Option	Investment cost (thousand 1983 dollars per barrel per day of oil replaced)
CNG[a]	40-130[b]
LPG[c]	15-55[d]
Gasifier	35-105[e]
Ethanol production	70-95[f]

[a] Compressed natural gas.

[b] Assumes $2,300 to $3,600 per vehicle, including pumping facilities, and that vehicle gets 22 mpg of gasoline and is driven 10,000 to 20,000 miles per year.

[c] Liquefied petroleum gas.

[d] $1,000 to $1,500 per vehicle; vehicle gets 22 mpg of gasoline and is driven 10,000 to 20,000 miles per yr.

[e] $1,000 to $1,500 per vehicle; vehicle gets 22 mpg of gasoline and is driven 10,000 to 20,000 miles per yr.; gasifier replaces half of the vehicle's fuel consumption.

[f] $75 to $100 million for a 50 million gal per yr distillery, for every 2 Btu of ethanol displacement, a net of 1 Btu of oil replaced.

SOURCE: Office of Technology Assessment and Gibbs & Hill, Inc., "Oil Replacement Analysis Phase I—Selection of Technologies," contractor report to Office of Technology Assessment, April 1983.

(which use 90 percent of the oil used for industrial heat and steam) plus electric utilities are insufficient to cover growth requirements plus fuel switching, the investment function can be disconnected and the total investment level specified directly. Assumptions and projections of investment patterns will be discussed further in the context of particular shortfall scenarios.

Besides gasoline for automobiles and fuel oil for heat and steam, there are many other refined products and end uses that total about 40 percent of total oil consumption (see table 27). However, they are not nearly so attractive as targets for oil replacement because they serve indispensable functions, primarily in the industrial sector. For example, as discussed in chapter V, diesel

Table 27.—Petroleum Uses Largely Excluded From Technological and Economic Analysis of Oil Replacement

	1982 consumption (million barrels per day)
Distillate for transportation	1.38
Distillate for other industrial engines	0.35
Residual for water transportation	0.55
Material feedstocks	
Distillate	0.13
Residual	0.22
Light hydrocarbons	1.00
Jet fuel	1.03
Other (e.g., asphalt, lubricants, still gas, petroleum coke)	1.80
Total	6.46

SOURCE: Energy Information Administration, *1982 Annual Review of Energy*, Washington, DC, April 1983, table 31, p. 69; and Office of Technology Assessment, based on data developed by Jack Faucett Associates. See note above.

engines for commercial transportation and for industrial drive are largely irreplaceable and are already fuel efficient, given load requirements. Efficiency has been achieved there and not for personal automobiles because in business applications fuel cost has been a much larger fraction of total costs and has been otherwise of greater concern because value is mainly a matter of horsepower and cost, not all the other performance and appearance features that sell cars for personal property. For similar reasons, jet fuel and residual fuel for transportation were not treated.

The two other largest blocks of petroleum—industrial feedstocks (mainly liquefied petroleum gas and ethane) and asphalt—were excluded because they have no practical alternatives. However, consumption of all petroleum products, including the 40 percent that have been excluded from the replacement analysis, will be reduced during a shortfall. Some of this across-the-board savings has been simulated via product mix shift and GNP losses (see below). Beyond that, no doubt some oil savings have been excluded that would have occurred with sharp price increases, but these have been ignored in order to focus on technological options that provide the greatest opportunities for oil replacement at the least cost.

Guidelines for the Rest of the Economy

Unlike energy-related activities in the model, which are carefully programmed to conform to prior engineering results, the rest of the INFORUM model was calibrated only after initial simulation results were obtained. At this intermediate stage in OTA's analysis, the limited goal for calibration is only rough consistency of model outputs with established norms for macroeconomic behavior and with related simulation outputs from comparable macroeconomic models. Only when certain results appeared to be anomalous was an effort made to reconsider nonenergy-related assumptions.

Comparisons to 14 other macroeconomic models could be made relatively easily owing to the recent completion of the Energy Modeling Forum study of macroeconomic impacts of major energy shortfalls (commonly called EMF-7).[10] Included in this assessment of energy/economic models was one scenario calling for a 50-percent indefinite increase in the real price of oil. Although such a shortfall is less severe than the one postulated in this assessment, it nevertheless raised the same set of adjustment problems and, as discussed below, the general characteristics of that model's 14 projections were comparable to the present model projections.

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[10] See B. G. Hickman and H. G. Huntington, "EMF-7 Study Design," EMF Report 7.1, and "Macroeconomic Impacts of Energy Shocks and Overview," EMF Report 7.2, Energy Modeling Forum, Terman Engineering Center, Stanford University, Stanford, CA. These two reports summarize information contained in 17 companion reports.

The first major macroeconomic checkpoint involves investment behavior. Rapid oil replacement may put too great a burden on national capital markets. The extent of this potential problem can be evaluated by comparing total investment requirements for oil replacement to certain related financial aggregates. Assuming an average investment of $50,000 per barrel per day replaced,[11] total capital outlays for replacement of 3 MMB/D would amount to $150 billion. Spread over 5 years, it would equal $30 billion per year. While these are large numbers, they are not overwhelming when compared to current private domestic investment.

In 1982, private investment in producer durables was just over $200 billion. Assuming that 80 percent of oil replacing investment would fit into this category, oil replacement could lead to a 12-percent decrease in capital available for other purposes, or conversely, it would require an overall increase of 12 percent in total investment. (Note also that 1982 investment was relatively low owing to the most severe recession since the Great Depression.) Assuming that the remainder of oil replacement involves structures, the remaining $6 billion amounts to about 2.5 percent of total 1982 residential and nonresidential investment in structures.

While these appear to be manageable shares of total investment, given the apparent extremity of the shortfall, there is one additional comparison that reinforces the expectation of investment feasibility. Assuming that oil prices would double (from roughly $30 to $60 per barrel, see below for rationale) and that domestic oil production can be maintained at 8.5 MMB/D, then domestic oil revenues would increase by $93 billion annually, or three times the annual capital requirement for oil replacement. Some of this increase would undoubtedly be made available via normal market channels or by a policy of windfall profit taxation and investment subsidy.

The second general macroeconomic checkpoint concerns labor productivity over time. Growth in labor productivity in the longer term depends on investment in better tools and new processes, but the choice among such investment options and the volume of such investment may be significantly affected by sharply rising energy prices. The choice may change because labor will become relatively less expensive compared to energy, so the return on labor-saving/productivity-enhancing investments will fall due to the oil shortfall. Also, as discussed above, the volume of productivity-enhancing investments may decline generally owing to "crowding out" by investments in oil replacement.[12]

The net result on growth in labor productivity during a shortfall is difficult to anticipate. Unfortunately, the INFORUM model did not project either investment effect on productivity, so these were specified by OTA as an input to the model (in terms of a range of plausibility). At the minimum, given low investment costs for oil replacement and low oil price inflation, labor productivity was set to decline by 4 percent below the level achieved in the reference case by the fifth year after the initial curtailment. At the maximum, given high investment costs and high oil price inflation, labor productivity was set to decline by 8 percent below the reference case. (See below for further description of assumptions for the two shortfall scenarios.)

Since OTA was primarily interested in the energy sector, other calibration efforts related to the rest of the economy were not reported. However, integrated into the larger economic framework were two mechanisms for oil saving that help achieve a balance between oil supply and oil demand. First, the mix of goods and services shifts away from oil-intensive products and toward products that use relatively little oil. Second, total economic activity declines in the shorter term in response to lost real income and thus lower consumer demand, and in the longer term to reflect the fact that the energy resource base has now become significantly smaller.

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[11] This is a rough upper boundary for capital costs of oil replacement for technologies which would actually be deployed. See ch. III.

[12] This term usually refers to diversion of private savings from the private to the public sector in order to finance the Federal debt. Perhaps another label should be attached here, but the analogy is appropriate in the sense that expected investment behavior is interrupted by extraordinary circumstances.

Both of these more indirect means for oil replacement are initiated by rising oil prices, just as the latter provide incentives for motorists to buy more fuel-efficient cars or for firms to replace oil-fired boilers. The price mechanism will be discussed in the next section. At this point it is important to note that the two major model projections of interest for oil consumption are product mix shifts and GNP adjustments.

Guidelines for Scenario Integration by Iteration on Fuel Prices

The INFORUM model is calibrated assuming two alternative oil supply futures. The first, or reference case, assumes that total oil consumption will be maintained at about 16 MMB/D for the period 1985-95. A second type of scenario assumes that total oil consumption must contract to about 13 MMB/D from 1985 on. The reference scenario is run first to provide a performance check on the general economic characteristics of the INFORUM model, and it is then used as a standard for comparison with subsequent shortfall scenarios.

For both types of projections, the path taken by oil prices over time determines the rate of oil consumption because price incentives drive producer and consumer decisions toward efficient outcomes. Prices of all goods and services serve as economic drivers but other prices will not be discussed except to the extent that they are affected by oil prices. Furthermore, the oil price path is technically inputed into the model, not derived from the model, because the price of oil is substantially determined by conditions external to the national economy. (Based on the price of oil and other primary resources, the model sets the full range of intermediate and final product prices.) Careful side calculations, as well as iterations of the model assuming alternative oil price paths, are necessary to calibrate a final, realistic oil price path for each prescribed oil consumption scenario. This section describes how oil price paths were determined for the scenarios presented below.

For the reference case, the oil price path was set so that oil consumption remains at about 16 MMB/D from 1985 through 1990. This level rate of oil consumption was achieved with no change in real oil prices which are held at around $30 per barrel through 1990 (see table 28). While this single price/consumption projection does not reflect the considerable economic uncertainties which in fact exist, the latter were not considered to be significant, given that our primary purpose is only to establish a single, more or less realistic baseline for purposes of comparison to shortfall scenarios.

Table 28.—Petroleum Price Projections: Real Crude Price Per Barrel and Product Price Indices

	Reference case			Disruption case A			Disruption case B		
Year	Crude	Refined[a]	F. Oil[b]	Crude	Refined	F. Oil	Crude	Refined	F. Oil
1982[c]	32	158	158	—	—	—	—	—	—
1984	30	158	151	—	—	—	—	—	—
1985	30	150	150	55	258	227	77	342	301
1986	30	149	149	53	249	216	73	322	278
1987	30	148	148	53	249	213	73	319	273
1988	30	149	149	55	254	214	75	323	272
1989	30	150	150	55	256	213	75	327	272
1990	30	148	148	55	255	209	75	320	263

[a] Refined products include all petroleum products except #2 distillate, #6 residual, and diesel fuel.

[b] Fuel oils include the exceptions mentioned above. This breakdown was dictated by the INFORUM model sans energy skirt. With the energy skirt, separate prices are calculated for six petroleum products.

[c] Referenced to actual prices.

SOURCE: Office of Technology Assessment.

For the simulation of oil shortfall, two oil price projections were used, both of which yielded approximately 3 MMB/D reductions in consumption in order to illustrate the range of uncertainty associated with engineering cost estimates and investor responses. The first shortfall projection (A) assumes that the capital costs for oil replacement presented in table 25 are indeed accurate and that investor response to oil replacement opportunities is strong. The second shortfall projection (B) assumes that both of these economic situations are markedly less felicitous. So, in effect, it takes a much higher price incentive to save oil in the second case (B) than in the first case (A). As discussed above, in both shortfall situations, the schedule for oil replacement is indicated in simulation runs by adjustments to input/output coefficients and by oil price responses built into investment behavior functions.

The ballpark for oil price inflation in both shortfall simulations can be roughly inferred from investment requirements for oil replacement (table 25). While these outlays are only one consideration in the decision to replace oil, for the bulk of replacement actions taken after the initial curtailment, they are the deciding factor because the economic tradeoff is essentially capital versus fuel cost. The following examples illustrate this situation.

First, consider fuel switching to coal in large boilers. In 1982, the use of oil in large industrial and utility boilers was about 1 MMB/D, and the total for oil and gas exceeded 3.5 MMB/D oil equivalent. Even though limitations on engineering resources and construction leadtimes limit coal substitution for there fuels within 5 years (see ch. VI), the total for gas and oil is relevant because gas is such a good oil substitute for stationary heating and because the full potential for switching away from premium fuels in large boilers is pertinent to long-term expectations for energy price stability. This fuel switch greatly reduces operating costs for boilers, because coal costs much less per Btu than the two premium fuels, and the price of coal is likely to remain steady due to large domestic reserves.[13] To be conservative, however, assume that operating costs for new or converted coal boilers are equal to what they are (or were) using oil and gas prior to the shortfall, then the $50,000 per barrel per day (upper boundary) investment cost for coal utilization can be profitably amortised if the price of oil rises by about $23 per barrel and holds at that level (or goes higher).[14]

To infer the necessary price incentive for switching to gas or electricity in residential and commercial heat and hot water is more complicated because gas and electricity are also premium fuels whose price can inflate with the price of oil as people try to make the easiest (i.e., least capital cost) oil substitions (e.g., resistance space heaters and replacing oil with gas in dual-fired boilers). However, within the 5-year time horizon, gas price inflation will be restrained by several economic adjustments discussed above: 1) increased fuel efficiency in buildings and industry (ch. V), 2) increased domestic gas production based on current excess capacity (ch. IV), 3) switching to coal in large boilers (see previous paragraph).

The price of electricity can be restrained and the supply increased by increasing generation capacity based on coal or other nonpremium fuels. Furthermore, replacement fuel (gas or electricity) costs for these two stationary heating services can be controlled by another means—investment in insulation which has an estimated cost per barrel of oil replaced which is comparable to the coal switching option described above. However, even without taking into account increased insulation and other means for increasing fuel efficiency, the upper limit for the increase in gas demand for oil replacement in the "high-response" case is 11 percent above current consumption (ch. VI), a very manageable increase.

Finally, behavioral changes can also reduce oil consumption and limit the need for expensive investments in oil replacement. These include turning down the thermostat and driving less, and they also include the oil savings which occur indirectly when rapid oil price inflation reduces general economic activity. Unlike oil replacement, these behavioral changes are computed entirely within the model and their relative importance can be estimated only by running the model. Since the overall level of investment is also determined within the model, it means that shortfall simulation must be done iteratively with adjustments made in oil price until the net effect in terms of oil savings equals 3 MMB/D.

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[13] During each of the earlier shortfalls, the real price of crude oil approximately doubled, and since 1973 the real price of natural gas at the wellhead also has increased by about a factor of 4. Coal, on the other hand, doubled in price only during the 1973-75 period. It remained level or declined marginally since that time and it is unlikely in the future to experience inflation similar to the premium fuels due to very large domestic reserves.

[14] If, to be conservative, we assume a 10-year lifetime and a 10 percent rate of return (ROI) over that period (a normal lifetime would be closer to 20 years and a normal ROI would be closer to 5 percent) then capital costs of $50,000 per barrel per day could be profitably amortized once oil prices have risen by $23 per barrel (or by about $4 per million Btu).

In fact, the "high-response" simulation settled on oil prices in the range of $50 to $55 (1983 dollars, see table 28). In other words, the inferred price increase based on the investment outlays of $50,000 per barrel of oil per day replaced appears to be a reasonable estimate for the necessary price incentive to effectively replace the oil shortfall.

On the other hand, what if the capital costs estimates were too low and the estimated response of investors to oil replacement opportunities too high? What if investment requirements were off by 50 percent? That would raise the necessary price incentive proportionately. What if perceived risks in investment were twice as large? That could be illustrated as a doubling in the required rate of return and that would raise the necessary price incentive by another 50 percent. The point is not to guess errors in the economic projections but rather to suggest a plausible upper boundary for oil price inflation as an input to the future simulation. For model iterations leading to the "low-response" scenario, the oil price in fact settled at a level of about $75 per barrel, corresponding to a price increase approximately twice as large as that in the "high-response" case.

A much larger study might explore additional scenarios that incorporate alternative assumptions about rate of technology deployment, investment cost, natural gas supplies, and the key macroeconomic variables described above. However, these two shortfall projections bracket the range of economic conditions most pertinent for this assessment, given OTA's primary data base related to oil replacement technology and given OTA's goals to establish rough orders of magnitude for shortfall impacts and how they might depend on the rate of technology deployment. The high-response scenario simulates how easy and the low-response scenario how hard it might be to live with 3 MMB/D lower oil imports.

ECONOMIC PROJECTIONS

A Normal Economic Projection: The Reference Case

In 1983, after many recent predictions by prominent macroeconomic models have proven wrong, there is obviously much uncertainty about how the economy will perform in the next decade. This uncertainty is manifest in serious academic and political debates surrounding trends in labor productivity and the even stronger debate over Federal monetary and fiscal policy.

In this assessment, a single future scenario is projected for the U.S. economy. Its purpose is not to predict the future, nor to define some "normal" future projection, but rather to establish a baseline or reference case that merely illustrates assumptions made in this assessment regarding future oil import dependence for the U.S. economy.

In general terms, the reference case describes an economy poised to maintain steady modest growth of GNP over the period 1986-90, after making a robust recovery from 1983-85. Unemployment falls sharply during the recovery and much more slowly during the period of modest growth. Inflation also falls sharply during the recovery but then rises steadily as capacity limits force the economy into a much lower rate of growth. There are other key variables, such as the behavior of investors and consumers, but the overall impression conveyed by general trends in GNP, unemployement, and inflation is sufficient to suggest how the economy is poised at the onset of the postulated oil shortfall. Further discussion of these variables and others, in terms of comparisons between the shortfall and reference scenarios, is presented in the next section.

Within this reference scenario, energy patterns reflect recent historical trends. Oil and gas prices hold steady (in constant dollars), and consumption of both premium fuels remains steady because the growth in demand associated with expanding economic activity is offset by capital investment in new technology (e.g., more fuel-efficient cars and fuel switching in boilers as obsolete units are replaced). Electricity grows in step with the economy, and coal consumption grows more rapidly as the fuel of choice in new boilers.

Two Macroeconomic Projections of Oil Import Shortfall Impacts

With the reference case as background, the model is used to project how the economy might adjust to a curtailment of 3 MMB/D in oil imports. Needless to say, the shock to the economy would be massive, and many important impacts would undoubtedly be impossible to predict given current knowledge about the economy. In the latter category, especially, would be the emergency predicaments facing families, firms, industries, and regions of the Nation during the first year, when the economy would be highly unstable. However, OTA's plan is to consider short-term conditions only to the extent that they contribute to the economic situation 5 years out, when the shock will have dissipated and some measure of economic order should have reestablished itself, much as it has following the shocks in the 1970s. Although the shortfall postulated here is unprecedented, OTA believes that much has been learned from the earlier experiences concerning the value and priority of alternative oil uses and concerning the U.S. ability to do without normal supplies if necessary.

Two shortfall projections are described below. The first (the high-response case A) simulates an extremely optimistic scenario where investments in oil replacement have been large and well targeted to fuel switching for heat and steam applications (where they displace the most oil for the least cost) and where actual investment costs per barrel replaced are relatively low. About 2.2 MMB/D of the 3 MMB/D loss in imports are effectively replaced in stationary heat and steam after 5 years, leaving only about 0.8 MMB/D for replacement elsewhere.

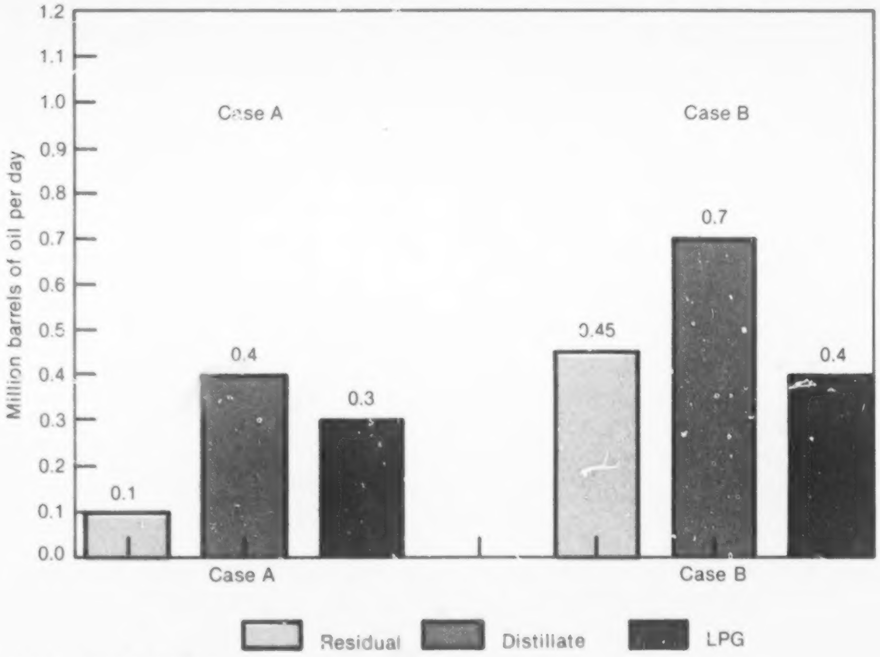
The second shortfall case (the low-response case B) is less optimistic about the size and targeting of investment as well as about actual investment cost per barrel replaced. In terms of oil consumption, figure 44 shows that 0.75 MMB/D more oil is replaced from stationary heat and steam applications in case A than in case B, which means that much less is available for use in engines in case B (see fig. 45). (Note in reading the figures that the vertical scales change.) It also means that crude oil prices must be driven up by more than twice as much as in case A to create an investment incentive and to displace or choke down transportation and general economic activity as an alternative means to achieve the necessary total of 3 MMB/D savings (see table 28 for oil prices).

Note that rates of oil consumption reported in these shortfall scenarios (figs. 44 and 45) represent the combined effects of technological replacement and behavioral adjustments. Both are motivated by higher oil prices, but behavioral adjustments also occur as a result of reduced economic activity. This combination of technological and behavioral responses to oil shortfall is a major extension of the engineering analysis presented in earlier chapters, and it is an essential aspect of an integrated assessment of potential macroeconomic impacts from oil shortfall.

As the following discussion of key macroeconomic variables indicates, the two oil replacement scenarios lead to different states of the economy. Although the effective oil savings is the same in both scenarios, the differences in investment costs and oil prices lead to major differences in the apparent costs to the economy of the oil curtailment. These differences are illustrated in figures 46 through 50.

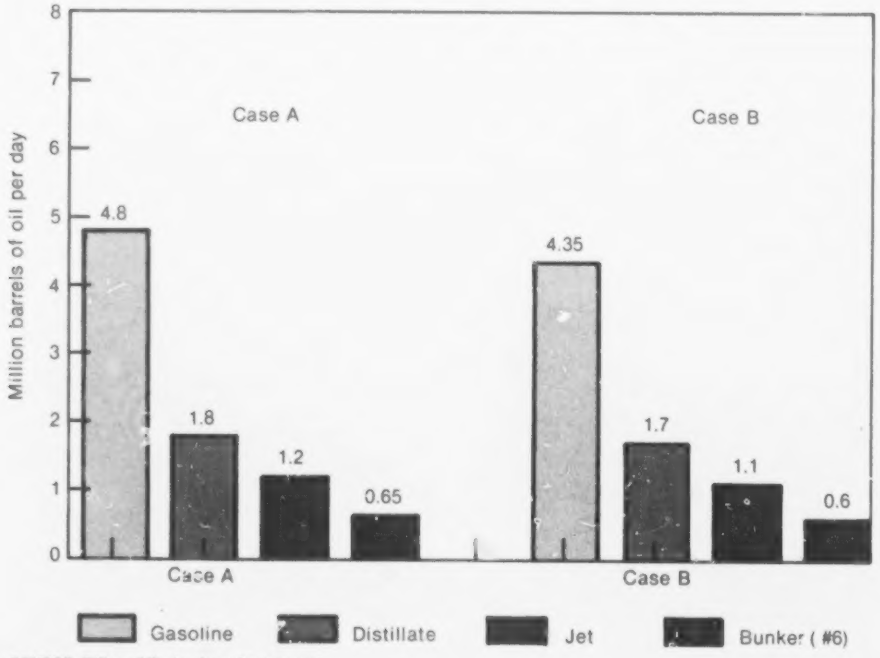
The following discussion considers five key macroeconomic variables plus product mix shift. For each, the implications of a shortfall are presented in the order of their reliability, given that

Figure 44.—Comparison of Shortfall Projections (petroleum use for heat and steam)



SOURCE: Office of Technology Assessment.

Figure 45.—Comparison of Shortfall Projections (petroleum use by engines)



SOURCE: Office of Technology Assessment.

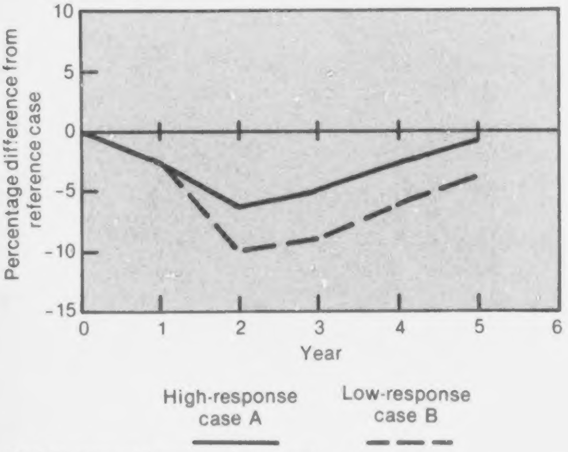
the primary OTA data base pertains to long-term technology deployment and given the strengths and weaknesses of the INFORUM model of the U.S. economy. Although consideration of each variable will include its time path during the entire 5-year period following the onset of a shortfall, the year-to-year fluctuations are considered much less significant in all cases than 5-year averages and trends established after 5 years of economic adjustment.

Gross National Product

While there are many other statistics that describe important dimensions or patterns of national economic behavior, including the five discussed below, a general perspective on potential economic impacts, from a permanent shortfall of oil imports, can be obtained most easily by comparing the alternative time patterns for GNP presented in figure 46. This comparison can be made from several different viewpoints, and these are discussed in order of their relevance and reliability, given the design of this technology-based study.

Up to the 5-year horizon after the initial import curtailment, projected GNP lies well below that in the reference case, but the difference caused by the shortfall narrows over time, since the shortfall apparently does not reduce the potential for growth in the economy. Furthermore, after 5 years, the annual loss in GNP due to the shortfall may be considered manageable in the sense that it can be made up in 1 to 2 years by continued economic growth, which in all these projections moves around a trend rate of 2 percent annually. This conclusion should not be surprising, given the wide range and large size of technological opportunities for oil replacement described in the preceding chapters, but it does reinforce from a macroeconomic perspective the conclusion that there is considerable flexibility in the economy to respond to a large oil shortfall.

Figure 46.—GNP: Two Shortfall Projections Percentage Reductions From Reference Case



SOURCE: Office of Technology Assessment.

A second general observation concerns the average loss in the level of GNP over the first 5 years after a shortfall compared to that in the reference case.[15] In the high-response replacement scenario, the permanent loss of oil imports lowers GNP on the average by about 3.5 percent compared to the reference case. In the low-response scenario, the average loss is about 6.2 percent. Note that the differences between the reference and two shortfall projections are much larger during the first 2 years and much smaller during the last 2 years. In part, this unevenness over time is due to a macroeconomic cycle caused by the onset of the shortfall (see below), but a major reason why GNP comes back 5 years later is because investments in oil replacement have reduced the burden of high energy costs on the economy.

A third and less important comparison (from OTA's longer term perspective) involves year-to-year change in the GNP during the first 2 years following the onset of the shortfall (note that this information is not contained explicitly in fig. 46). While growth trends and average output over 5 years are most interesting, given the model used, this shorter term perspective is probably most important for public perceptions of economic hardship. In both shortfall cases, the only actual decline of GNP occurs in the second year after the curtailment begins. The decline in the optimistic case A is only 1.3 percent from the previous year and 5.2 percent in case B. This difference can be appreciated by noting that during the worst recession since the Great Depression, real GNP declined in 1982 by 1.7 percent from 1981. The recession just prior to that, from 1979 to 1980, involved only a 0.2-percent decline in GNP.[16] In other words, case A is within recent historical experience; case B is well outside of it.

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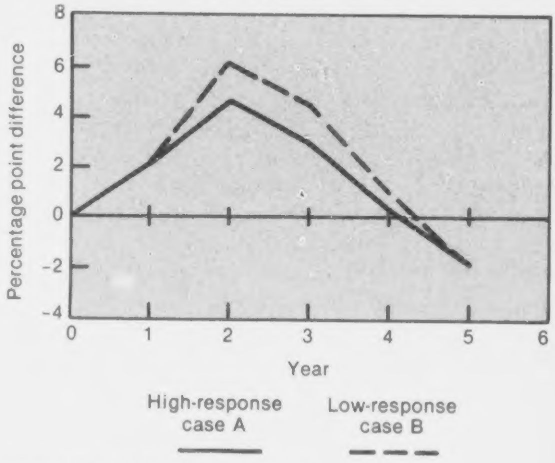
[15] Please note that the model's behavior at the start of the postulated shortfall in 1985 is strongly influenced by current expectations that the economy will have considerable growth momentum. If, on the other hand, the United States were mired in recessionary doldrums, the projections could be quite different.

A series of test runs with the model indicate that oil price inflation would be the main factor driving the economy down into a trough 2 years after the shortfall begins. While most of these projected losses are made up shortly, the economic recovery may not in fact be so energetic if the model has been too optimistic about the dynamics of unemployment and inflation. As discussed further below, macroeconomic instabilities (resulting from a rapid and large oil price inflation) can become chronic, making it difficult for investors, managers, and workers to see and to adjust to new long-term trends. Consequently, it would be much safer if initial oil price inflation could be moderated. Based on the technical analysis presented in this study, moderation can be achieved by rapid and extensive deployment of oil replacement technologies. When such replacement is reliably expected in the future, this expectation feeds back to the short-term market behavior of oil users and price speculators, who would thus be encouraged **not** to hoard and speculate against the prospect of more severe oil price inflation. Since, in the short run, price expectations appear to be self-fulfilling, the favorable longer term prospects for oil replacement can cap and otherwise stabilize short-term oil prices.

Unemployment

On the average, over the 5-year shortfall period, unemployment would be pushed up by the shortfall by over 1.7 percentage points in case A (high-response) and by over 2.3 percentage points in case B (see fig. 47). However, after the initial, sharp runup associated with the deep recession (in the second year after the start of the shortfall), the rate of unemployment would drop sharply until it actually fell below the reference case. This surprising result raises important questions about labor and capital markets, but before considering them, it should be emphasized that the projected differences between 5-year average unemployment rates (among the three future projections) are the most important and reliable result from this model.

Figure 47.—Unemployment: Two Shortfall Projections Percentage Point Changes From Reference Case



SOURCE: Office of Technology Assessment.

In this model, the sharp decline in unemployment after the second year is due to a combination of conditions that lead to the substitution of labor for energy. This happens: 1) because of "crowding out" of investments (which in normal times would increase labor productivity and reduce labor demand per dollar of output, see note 12 above and the discussion of investment below) by investments that replace oil; 2) because real wages decline sharply; and 3) because the rapid economic expansion following the recessionary trough (2 years after the curtailment) is driven by aggressive investment behavior, which increases labor demand in general. Investment by industry is based on behavioral equations in the INFORUM model. The "crowding out" affect was programmed into the shortfall cases, and real wages were assumed to change as necessary to move the economy toward full employment.

Compared to other macroeconomic modeling of oil shortfalls, this result about unemployment and the previous results for GNP are relatively optimistic.[17] This is because instabilities associated with unemployment, inflation, and Government deficit (see below) are treated by INFORUM as temporary problems, not chronic disorders. They are temporary, at least to the extent that they are exacerbated by the oil supply shortfall, because real wages adjust quickly (downward) to the level necessary to achieve full employment and because investment behavior is robust (see below). If wages were not so flexible or investors not so responsive, unemployment 5 years after the shortfall begins could indeed be abnormally high; and furthermore, it could take much longer for the economy to recover from the recession brought on by the onset of shortage.

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[16] Data obtained from *Survey of Current Business*, April 1981 and April 1982.

Comparisons among models, which lead to rather different projections for shortfall impacts, suggest that all such projections should be interpreted cautiously. Caution is necessary because economic uncertainties, which go far beyond those directly related to oil replacement technologies, are very large. A major permanent loss of imported oil, such as the one postulated in this study, could make the chronic macroeconomic problem of unemployment (and inflation, see below) much more troublesome than anything experienced during the last decade; or it could serve as a catalyst for market reorganization, which means that workers, firms, and investors, must compete more vigorously, with the resulting discipline and efficiency that competition engenders. While the present modeling analysis does not reduce this uncertainty, its relative optimism is consistent with the preceeding analysis of technology, which suggests that market conditions, in general, should be positively affected by relatively large technological opportunities for oil replacement.

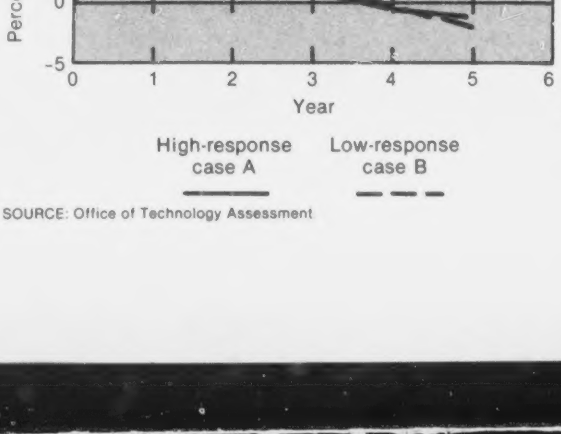
As a final note about unemployment, the year-to-year changes in unemployment during the first 2 years suggest the potential severity of the short-term problems for the economy and for workers in particular. Compared to the reference case, both shortfall cases reverse a declining trend in the rate of unemployment. Furthermore, the post-disruption peak for case A closely approximates the 1982 peak annual rate of 9.7 percent, and in case B the peak exceeds the 1982 peak (which was a postdepression high) by about 1.3 percentage points.

Inflation and Federal Macroeconomic Policy

The third major index of macroeconomic health is inflation, in particular the rate of growth in the GNP deflator. In a pattern very similar to its impact on unemployment, the path that prices take over time is shaped like a spike, with a peak unprecedented since 1946 (see fig. 48). In other words, when oil prices shoot upward in response to reduced supply, they sharply drive up the average price level, but soon after (as oil prices level off) the rate of inflation falls quickly back down to the reference case. Over the 5-year shortfall period, the shortfall increased the average annual rate of inflation by about 2.7 percentage points in case A and 5.4 percentage points in case B.

This result must be heavily qualified, however, because so little is known about inflationary dynamics and because so much depends on Federal monetary and fiscal policy. Federal policy depends on changing perceptions about macro-

Figure 48.—Inflation: Two Shortfall Projections Percentage Point Changes From Reference Case



SOURCE: Office of Technology Assessment

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[17] Results reported by the Energy Modeling Forum (EM7) indicate a range of GNP losses from 2 to 4 percent, 4 years after a disruption, assuming a permanent increase in oil prices of 50 percent. Since OTA's price projections are either somewhat higher (70-percent increase for case A) or much higher (120-percent increase for case B), OTA's conclusion that GNP losses fall in the same 2- to 4-percent range is by comparison optimistic.

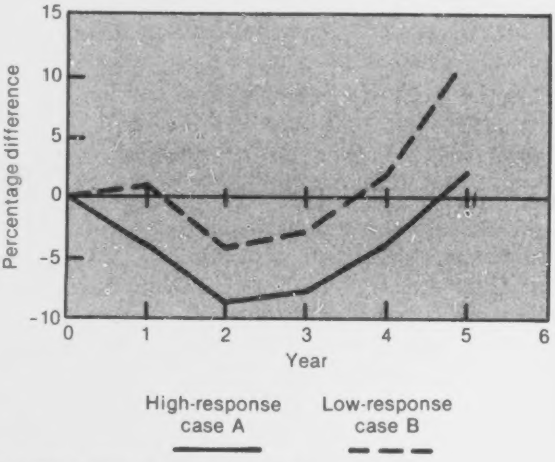
economic behavior, international relations, and the relative strength of concerns about inflation and investment incentives on the one hand versus unemployment and inequity on the other. Needless to say, in the event of an actual oil shortfall, there would be many controversial policy issues to resolve. This model (and perhaps any current macroeconomic model) does not attempt to simulate complex, political choices. However, as a first order approximation, OTA assumes that the money supply will be held to a constant annual rate of growth (6 percent) (i.e., no allowance is made to accommodate inflation caused by the discontinuous jump in oil prices). This stability in the money supply is perhaps the main reason why inflation is forced to moderate quickly. Also, by adjusting taxation, the Federal deficit was allowed to increase as a percent share of GNP in response to the oil curtailment. In both shortfall cases, the share of the Federal deficit in GNP increased by 1 percentage point over the reference case, from about 3.2 percent to about 4.2 percent.

The optimistic result in the present projections, that inflation will quickly moderate, figures heavily in limiting GNP losses in both shortfall cases. It does so by focusing investor attention on plant and equipment (instead of, for example, gold and real estate), and thus it makes investment a force sufficient to drive the economy smartly out of its initial recessionary trough.

Private Investment

The key to both oil replacement and economic growth during the shortfall is investment (see fig. 49). As discussed above, the projected strong recovery 3 to 5 years after the oil cutoff is to a large extent driven by robust private investment. In the economy and in this economic model, investment behavior (or the decision to invest) depends on general economic expectations, including among many other things relative oil prices, as well as on the set of new technologies that makes new capital investment more productive than existing capital stock. While the robust behavior projected by the model was determined by its investment behavior functions, this result is consistent with and to an extent corroborates the technological conclusions of the earlier chapters.[18] That is, by and large, oil and capital assets are substitutes for each other, and thus there are many profitable investment opportunities to replace oil by the time crude oil prices increase by 70 to 140 percent above their current level of around $30 per barrel.

Figure 49.—Investment in Producer Durables Percentage Change From Reference Case



SOURCE: Office of Technology Assessment.

Weighing against this optimistic, longer term perspective, are short-term obstacles to investment that are caused by a deep recession that can be expected immediately following the cutoff. When the economy is headed down or settled into a recessionary trough, investors, entrepreneurs, and corporate managers understandably reduce investments in production of most goods for which demand is stagnant or contracting. Firms, in particular, do this in order to reduce the associated financial risks and to build liquidity, which could, if necessary, be used to shore up established market positions.

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[18] The strikingly rapid recovery 3 to 5 years out is caused also by a number of other factors typical of a Keynesian, "demand-driven" macroeconomic model. All of them are self-corrections embodied in the initial very severe inflation and recession. First, one of the forces underlying robust investment is the large pool of industrial profits for oil-related industry. In the model, this pool of liquidity motivates investment. Second, although high interest rates make borrowing more expensive, they also increase the income of creditors, and like oil profits, this enlarged pool of funds becomes liquidity available for investment. Finally, high unemployment rates drive down personal savings, since, on the average, people have lower budgetary surpluses above basic consumption needs. Thus, as the recession becomes worse, it increases the marginal propensity to consume and thus increases the associated income multipliers which make a dollar of investment worth more in terms of the economic activity it can generate (i.e., it has a greater impact on GNP). While all of these demand-side adjustments are no doubt significant, it would have been better to model also the supply-side constraints associated with depletion of corporate funds by high oil prices, with inflation as investors attempt to shelter their funds against a depreciating dollar, and with chronic local and regional stagnation caused by widespread losses in real personal income. Unfortunately, neither the INFORUM model nor perhaps any of the major macroeconomic models has been able to simulate the highly complex interaction of both demand- and supply-side factors.

Because of the recession and related obstacles to investment immediately after the curtailment, productive capital is **not** replenished or at least does not expand at a "normal" rate, and thus the productivity of the economy **cannot** grow normally. (Productivity in this case is measured as output per unit of labor input.) Furthermore, following the postulated curtailment, investment patterns will shift toward oil replacement, at least temporarily, and away from technologies that increase labor productivity (since labor becomes relatively less expensive compared to energy). The latter diversion of funds from normal pursuits was called above a "crowding out" effect, an effect that reinforces the recessionary drag on labor productivity.[19]

Indeed, the recovery is so strong by the end of the fourth year in both shortfall scenarios that investment in producer durables, the key component of private investment related to labor productivity and oil replacement, exceeds that in the reference case. This particular aspect of these shortfall projections, like certain aspects of inflation and unemployment discussed above, appears to be extremely optimistic. While it may be plausible, it probably would not occur if the model had incorporated the likely negative "supply-side" conditions.[20]

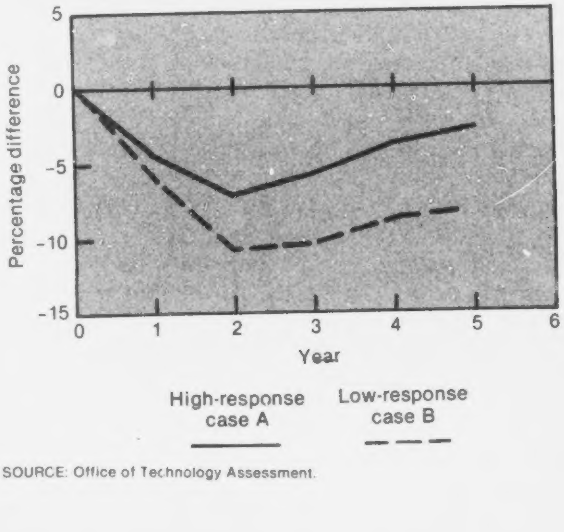
Personal Consumption Expenditures

The fifth summary viewpoint on macroeconomic impacts involves private or personal consumption expenditures (PCE). Along with private investment and government expenditures, personal consumption drives the economy (i.e., it determines the size and composition of GNP) through the decisions of consumers to use income for consumption purposes (see fig. 50) and through their decisions to allocate their consumption expenditures among alternative products. As with GNP, the oil supply shortfall interrupts the pre-1985 upward trends in total consumption expenditures for 2 years as the economy goes into a recession, and then growth trends reappear and make up some of the recessionary losses.

However, the average loss (compared to the reference case) in consumption over the 5-year period is greater than that for the GNP. In case A, PCE averaged 4.7 percent lower than in the reference case, compared to a loss of 3.5 percent for the GNP. In case B, PCE loss averaged 8.8 percent, compared to 6.2 percent for the GNP. Consumption losses exceeded GNP losses because investment led the way to the economic recovery and thus expanded its share in total economic activity.

Nevertheless, despite this shift from consumption to investment, the overall effect of the oil shortfall on consumption is more or less similar to its effect on the GNP. While the short-term hardships are severe, the longer term effect amounts to a temporary delay in the achievement of consumption objectives, not a permanent loss. The delay may be for a bit longer than for the recovery of the GNP, because the average loss over the

Figure 50.—Personal Consumption Expenditures Percentage Change From Reference Case



SOURCE: Office of Technology Assessment.

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[19] OTA has specified exogenously certain reductions in the rate of growth in labor productivity that have a large impact on projected GNP and unemployment. See p. 140 for further discussion.

[20] See note 18 above.

5-year period is somewhat larger, but the robust investment response eventually pays off in greater productive capacity and real income, and thus greater purchasing power for consumers.

Within total consumption, major product categories can be identified that describe consumption and how it changes. Table 29 presents product share data for the three future projections, 5 years after the oil import cutoff. At the first level of disaggregation, when total consumption is divided into just three gross categories, the impact of oil shortfall appears to be insignificant. Overall, durable goods, nondurable goods, and services share about equally in the lost personal consumption since they maintain their shares in total consumption. However, within each of these categories, certain changes are noteworthy.

Within consumer durables, the disruption shifts consumption away from motor vehicles, boats, recreational vehicles, aircraft, wheel goods, durable sports equipment, and jewelry but toward furniture and household equipment (especially household appliances, communications, and entertainment equipment, for which use actually increases significantly). In other words, as a result of higher energy prices, people may stay at home more often and wear less expensive baubles.

With insignificant exceptions, consumption of all nondurables declines, but two categories decline more and one declines less than others. The largest change occurs in food consumed at home, which increases its share of total nondurables by more than 1 percent. That comes about primarily at the expense of gasoline and oil and clothing. The 15 other product categories decline more or less in step with one another.

Among consumption service categories, the major shift was away from housing and toward operating activities within households. The two

Table 29.—Product Mix for Personal Consumption Expenditures (PCE) After 5 Years (in percent, using 1972 product prices)

Gross product mix	Reference case	Case A	Case B
Durable manufactures	16.0	16.0	15.4
Nondurable manufactures	35.6	35.8	36.4
Services	48.4	48.2	48.2
Total	100.0	100.0	100.0
PCE durable manufactures:			
Motor vehicles and parts	37.3	34.3	32.1
Furniture and household equipment	44.1	47.9	50.9
Other	18.5	17.9	17.0
PCE nondurable manufactures:			
Food and alcohol	49.4	49.9	50.5
Clothing	25.2	25.3	24.7
Gasoline and oil	4.5	4.0	3.9
Fuel oil and coal	.7	.6	.5
Tobacco	3.6	3.7	3.8
Drug preparations and sundries	3.3	3.2	3.2
Other	13.2	13.3	13.3
PCE services:			
Housing	38.3	37.3	36.5
Owner occupied	27.9	27.1	26.4
Tenant	9.4	9.2	9.1
Household utilities	14.4	15.5	16.3
Electricity	4.3	4.7	5.0
Telecommunications	5.7	6.3	6.7
Water	1.2	1.3	1.4
Transportation	6.7	6.5	6.3
Medical services	17.0	17.1	17.3
Education	2.6	2.7	2.7
Other	21.0	21.0	20.8

SOURCE: Office of Technology Assessment.

changes just about offset each other. Declines in housing stem primarily from high interest rates, which are driven up by shortfall-induced inflation. However, the effect of inflation and high interest rates on housing in the model may be somewhat exaggerated because the model reflects problems of "disintermediation," which occurred during the last two oil shortfalls, but which should be less significant in the future due to structural reforms in financial markets.[21] The increase in household activities mirrors the changes in consumer durables. The leading growth activity is telecommunications, with smaller increases in electricity, water and sanitation, and postage.

Product Mix Shift Over the Entire Economy

Compared to the previous discussion of consumption mix, product categories for the entire economy are much less detailed in terms of end uses, but they include intermediate goods and services which are entirely omitted from the classification of consumer products (see table 30). For example, the gross output mix includes lumber as well as furniture, ferrous metals as well as autos and electric appliances, and agriculture as well as food. While this is a broader classification system than was used for consumption, which leads to different relative product shares, the interesting point for analysis is the same—how product shares change as a result of the oil supply shortfall.

From this overall viewpoint on the economy, most of the product categories that increase their share in total output (at the end of 5 years) are related to private investment. This especially includes machinery for mining, metal working, engines and turbines, computers, and communications equipment. Presumably, the latter two types of machinery are related to the expected shift from energy-intensive transportation to electronics as means for conducting business and social relations. All of these producer durables increased their level of physical output as a result of the oil supply shortfall, not just their share in total output. The same is true for domestic gas and coal production because these products are direct substitutes for oil.

Table 30.—Product Mix for All Economic Activity (GNP) 5 Years After Curtailment
(in percent, using 1972 product prices)

Product category	Reference case	Case A	Case B
Agriculture, forestry, fishery	6.3	6.3	6.4
Mining	3.7	3.8	3.9
Construction	5.0	4.8	4.6
Nondurable manufactures	31.0	30.5	30.7
Durable manufactures	37.4	37.3	38.2
Nonelectric machinery	7.6	7.7	8.4
Electric machinery	5.9	6.1	6.5
Transportation equipment	7.9	7.7	7.7
Transportation services	6.4	6.4	6.4
All utilities	11.2	11.5	11.6
Wholesale trade	9.2	9.1	9.3
Retail trade	9.4	9.3	9.2
Eating and drinking establishments	4.6	4.5	4.4
Finance and insurance	6.4	6.3	6.3
Real estate	7.3	7.3	7.2
Owner occupancy housing	8.3	7.8	7.5
Business services	9.8	11.5	10.8
Medicine, education, NPO	7.8	8.6	8.7
Other services	7.3	5.3	5.8
Government industry	7.8	8.8	9.1

SOURCE: Office of Technology Assessment.

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[21] Disintermediation refers to the problem experienced in the past by the savings and loan industry, which has typically concentrated lending in long-term home mortgages and borrowing in short-term savings. During unstable periods in the past, when interest rates were abnormally high, large numbers of depositors sought higher returns from other financial institutions, leaving savings and loan institutions unable to make new mortgages and thus drying up the primary source of funds for residential construction. In the future, mortgage lending should be more resilient as financial institutions use variable rate mortgage instruments and otherwise diversify to minimize their own risks from inflation and to offer depositors greater investment flexibility.

Other product categories increased their share in total output by lessor amounts by suffering relatively small declines in physical output. Some of these, such as stone/clay/glass, ferrous metals, and paper are obviously related to the investment in producer durables, either as intermediate goods in their production or (as in the case of paper) as a complementary (communications) product. Others increased share because their use is not highly sensitive to price inflation, such as medicine and government enterprise.

On the other hand, products losing share in total output include most other major categories, and the losses are by and large marginal. However, the most signficant losses occur for housing (as discussed above) and for the construction industry, which suffers because many fewer homes are built as a result of high interest rates during most of the postcutoff period. Of course, the petroleum refining industry suffers a major loss in output due to diminished crude oil supplies. The production of motor vehicles also loses significantly in its share due to high fuel prices.

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